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 March 31, 2022
OR

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

For the transition period from to

Commission File 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. The registrant has filed all Exchange Act reports for the preceding 12 months (or for such shorter period that the registrant was required to file such reports)).

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 MARCH 31, 2022

GLOSSARY

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

Abbreviations or Acronyms	Definition
2018 Revolving Credit Agreement	Credit Agreement, dated as of April 25, 2018, between us and CFC, as administrative agent
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
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
COVID-19	coronavirus disease 2019 that was declared a pandemic by the World Health Organization in March 2020
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)
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
Jurisdictional PDO	our Petition for Declaratory Order on Jurisdiction under Part II of Federal Power Act, filed with FERC on December 23, 2019, EL20-16-000
kWh	kilowatt hour
LIBOR	London Interbank Offered Rate
LPEA	La Plata Electric Association, Inc.
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 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
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 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)

	March 31, 2022	December 31, 2021
ASSETS	(unaudited)	
Property, plant and equipment		
Electric plant		
In service	$ 5,621,069	$ 5,606,732
Construction work in progress	89,631	107,636
Total electric plant	5,710,700	5,714,368
Less allowances for depreciation and amortization	(2,379,048)	(2,367,197)
Net electric plant	3,331,652	3,347,171
Other plant	938,121	1,093,922
Less allowances for depreciation, amortization and depletion	(670,105)	(823,087)
Net other plant	268,016	270,835
Total property, plant and equipment	3,599,668	3,618,006
Other assets and investments		
Investments in other associations	164,276	163,097
Investments in and advances to coal mines	2,094	2,273
Restricted cash and investments	3,935	4,101
Other noncurrent assets	15,994	15,873
Total other assets and investments	186,299	185,344
Current assets		
Cash and cash equivalents	87,381	100,555
Restricted cash and investments	17,217	480
Deposits and advances	40,272	34,042
Accounts receivable—Utility Members	97,563	95,630
Other accounts receivable	18,969	21,571
Coal inventory	57,364	59,701
Materials and supplies	90,673	87,234
Total current assets	409,439	399,213
Deferred charges		
Regulatory assets	659,402	665,693
Prepayment—NRECA Retirement Security Plan	14,774	16,117
Other	41,224	35,139
Total deferred charges	715,400	716,949
Total assets	**$ 4,910,806**	**$ 4,919,512**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 990,030	$ 994,865
Accumulated other comprehensive loss	(1,888)	(1,460)
Noncontrolling interest	120,766	119,100
Total equity	1,108,908	1,112,505
Long-term debt	3,037,356	3,101,870
Total capitalization	4,146,264	4,214,375
Current liabilities		
Utility Member advances	14,382	17,217
Accounts payable	112,289	105,965
Short-term borrowings	119,946	49,997
Accrued expenses	30,752	32,882
Current asset retirement obligations	5,769	7,003
Accrued interest	43,825	25,716
Accrued property taxes	29,706	33,877
Current maturities of long-term debt	93,351	93,039
Total current liabilities	450,020	365,696
Deferred credits and other liabilities		
Regulatory liabilities	138,015	146,021
Deferred income tax liability	19,005	18,987
Asset retirement and environmental reclamation obligations	81,350	83,278
Other	63,107	78,319
Total deferred credits and other liabilities	301,477	326,605
Accumulated postretirement benefit and postemployment obligations	13,045	12,836
Total equity and liabilities	**$ 4,910,806**	**$ 4,919,512**

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 March 31,	
	2022	**2021**
Operating revenues		
Utility Member electric sales	$ 282,247	$ 272,798
Non-member electric sales	22,944	17,340
Rate stabilization	7,883	20,834
Other	12,128	15,000
	325,202	325,972
Operating expenses		
Purchased power	87,300	87,017
Fuel	62,474	60,547
Production	37,796	40,901
Transmission	47,182	44,671
General and administrative	20,273	14,587
Depreciation, amortization and depletion	41,475	52,755
Coal mining	1,526	1,541
Other	1,036	2,551
	299,062	304,570
Operating margins	**26,140**	**21,402**
Other income		
Interest	858	877
Capital credits from cooperatives	4,594	4,273
Other income	885	857
	6,337	6,007
Interest expense		
Interest	35,681	36,115
Interest charged during construction	(395)	(974)
	35,286	35,141
Income tax expense	18	109
Net margins including noncontrolling interest	(2,827)	(7,841)
Net margin attributable to noncontrolling interest	(2,008)	(1,649)
Net margins attributable to the Association	**$ (4,835)**	**$ (9,490)**

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 March 31,	
	2022	**2021**
Net margins including noncontrolling interest	$ (2,827)	$ (7,841)
Other comprehensive loss:		
Unrealized loss on securities available for sale	(176)	(34)
Amortization of prior service credit on postretirement benefit obligation included in net margin	(535)	(20)
Amortization of actuarial loss on executive benefit restoration obligation included in net margin	—	312
Amortization of prior service cost on executive benefit restoration obligation included in net margin	283	220
Unrecognized prior service cost	—	(1,121)
Other comprehensive loss	(428)	(643)
Comprehensive loss including noncontrolling interest	(3,255)	(8,484)
Net comprehensive income attributable to noncontrolling interest	(2,008)	(1,649)
Comprehensive loss attributable to the Association	**$ (5,263)**	**$ (10,133)**

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 March 31,	
	2022	**2021**
Patronage capital equity at beginning of period	$ 994,865	$ 978,519
Net margins attributable to the Association	(4,835)	(9,490)
Patronage capital equity at end of period	**990,030**	**969,029**
Accumulated other comprehensive loss at beginning of period	(1,460)	(5,714)
Unrealized loss on securities available for sale	(176)	(34)
Reclassification adjustment of prior service credit on postretirement benefit obligation included in net margin	(535)	(20)
Reclassification adjustment for actuarial loss on executive benefit restoration obligation included in net margin	—	312
Reclassification adjustment for prior service cost on executive benefit restoration obligation included in net margin	283	220
Unrecognized prior service cost	—	(1,121)
Accumulated other comprehensive loss at end of period	**(1,888)**	**(6,357)**
Noncontrolling interest at beginning of period	119,100	114,851
Net comprehensive income attributable to noncontrolling interest	2,008	1,649
Equity distribution to noncontrolling interest	(342)	(2,693)
Noncontrolling interest at end of period	**120,766**	**113,807**
Total equity at end of period	**$ 1,108,908**	**$ 1,076,479**

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)

	Three Months Ended March 31,	
	2022	**2021**
Operating activities		
Net margins including noncontrolling interest	$ (2,827)	$ (7,841)
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	41,475	52,755
Amortization of NRECA Retirement Security Plan prepayment	1,343	1,343
Amortization of debt issuance costs	665	627
Impairment loss	3,689	—
Deferred impairment loss	(3,689)	—
Rate stabilization revenue	(7,883)	(20,834)
Deposits (refunds) associated with generator interconnection requests	(6,108)	17,130
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,075)	(1,159)
Changes in operating assets and liabilities:		
Accounts receivable	(1,754)	10,224
Coal inventory	2,337	2,550
Materials and supplies	(3,439)	552
Accounts payable and accrued expenses	10,627	15,585
Accrued interest	18,108	17,800
Accrued property taxes	(4,171)	(5,291)
Other	(15,617)	(7,430)
Net cash provided by operating activities	**31,681**	**76,011**
Investing activities		
Purchases of plant	(22,034)	(22,775)
Changes in deferred charges	(3,285)	(9,786)
Proceeds from other investments	75	72
Net cash used in investing activities	**(25,244)**	**(32,489)**
Financing activities		
Changes in Member advances	(2,969)	1,536
Payments of long-term debt	(64,669)	(46,109)
Change in short-term borrowings, net	69,949	—
Retirement of patronage capital	(4,564)	(13,705)
Equity distribution to noncontrolling interest	(342)	(2,693)
Other	(445)	(322)
Net cash used in financing activities	**(3,040)**	**(61,293)**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**3,397**	**(17,771)**
Cash, cash equivalents and restricted cash and investments – beginning	**105,136**	**132,074**
Cash, cash equivalents and restricted cash and investments – ending	**$ 108,533**	**$ 114,303**
Supplemental cash flow information:		
Cash paid for interest	$ 16,401	$ 18,074
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (1,110)	$ (616)

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 Months Ended March 31, 2022 and 2021

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, 2021 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 March 31, 2022, results of operations and cash flows for the three months ended March 31, 2022 and 2021 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." The addition of Non-Utility Members in 2019 and specifically the addition of MIECO, Inc. on September 3, 2019 removed the exemption from the Federal Energy Regulatory Commission's ("FERC") regulation for us, thus subjecting us to full rate and transmission jurisdiction by FERC effective September 3, 2019. Our stated rate to our Class A members was filed at FERC on December 23, 2019 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. 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 significant intercompany balances and transactions in consolidation.

Jointly Owned Facilities

We own undivided interests in two jointly owned generation 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 generation 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 March 31, 2022 (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 %	$ 391,908	$ 256,305	$ 38
MBPP - Laramie River Station	28.50 %	525,312	338,011	3,160
Total		$ 917,220	$ 594,316	$ 3,198

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):

	March 31, 2022	December 31, 2021
Regulatory assets		
Deferred income tax expense (1)	$ 18,742	$ 18,742
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	78,560	79,133
Goodwill – J.M. Shafer (3)	42,735	43,447
Goodwill – Colowyo Coal (4)	34,870	35,128
Deferred debt prepayment transaction costs (5)	121,517	123,674
Deferred Holcomb expansion impairment loss (6)	82,976	84,145
Unrecovered plant (7)	280,002	281,424
Total regulatory assets	659,402	665,693
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	2,695	2,818
Membership withdrawal (9)	135,320	143,203
Total regulatory liabilities	138,015	146,021
Net regulatory asset	$ 521,387	$ 519,672

(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 related to the early retirement of the Nucla, Escalante and Rifle Generating Stations. The deferred impairment loss for Nucla and Escalante Generating Stations is being amortized to depreciation, amortization and depletion expense in the amount of $9.1 million annually through December 2022 and $11.3 million annually over the 25-year period ending in December 2045, respectively, and recovered from our Utility Members through rates. In March 2022, the Board took action for the early retirement of the Rifle Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $3.7 million during the first quarter of 2022. The Rifle Generating Station is anticipated to be retired from service in October 2022. Once retired, the deferred impairment loss will be amortized to depreciation, amortization and depletion expense through December 2028, which was the depreciable life of the Rifle Generating Station, 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 three months ended March 31, 2022, $7.9 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):

	March 31, **2022**	December 31, **2021**
Basin Electric Power Cooperative	$ 116,826	$ 116,826
National Rural Utilities Cooperative Finance Corporation - patronage capital	12,076	12,076
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,074	15,149
CoBank, ACB	14,328	12,985
Other	5,972	6,061
Investments in other associations	$ 164,276	$ 163,097

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 three months ended March 31, 2022 or during 2021.

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.

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

	March 31, **2022**	December 31, **2021**
Cash and cash equivalents	$ 87,381	$ 100,555
Restricted cash and investments - current	17,217	480
Restricted cash and investments - noncurrent	3,935	4,101
Cash, cash equivalents and restricted cash and investments	$ 108,533	$ 105,136

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 three months ended March 31, 2022, we recognized $0.3 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):

	March 31, **2022**	December 31, **2021**
Accounts receivable - Utility Members	$ 97,563	$ 95,630
Other accounts receivable - trade:		
Non-member electric sales	4,505	5,684
Other	8,837	13,505
Total other accounts receivable - trade	13,342	19,189
Other accounts receivable - nontrade	5,627	2,382
Total other accounts receivable	$ 18,969	$ 21,571
Contract liabilities (unearned revenue)	$ 5,554	$ 5,372

NOTE 6 – OTHER DEFERRED CHARGES

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

	March 31, **2022**	December 31, **2021**
Preliminary surveys and investigations	$ 12,490	$ 12,366
Advances to operating agents of jointly owned facilities	7,375	4,422
Operating lease right-of-use assets	7,326	7,529
Other	14,033	10,822
Total other deferred charges	$ 41,224	$ 35,139

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 $3.0 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") except for one unsecured note in the amount of $10.0 million as of March 31, 2022. 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 requirement on an annual basis and an equity to capitalization ratio requirement of at least 18 percent at the end of each fiscal year. Other than the Springerville certificates that has a debt service ratio requirement of at least 1.02 on an annual basis, all other long-term debt contains a debt service ratio requirement of at least 1.10 on an annual basis.

As of March 31, 2022, we had a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $650 million ("2018 Revolving Credit Agreement") that extended through April 25, 2023 and included a swingline sublimit of $100 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million. As of March 31, 2022, we had $530.0 million in availability under the 2018 Revolving Credit Agreement.

On April 25, 2022, the 2018 Revolving Credit Agreement was amended and restated by a secured revolving credit facility with CFC, as lead arranger and administrative agent, in the amount of $520 million ("2022 Revolving Credit Agreement"). The 2022 Revolving Credit Agreement has a maturity date of April 25, 2027, unless extended as provided therein.

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

	March 31, **2022**	December 31, **2021**
Total debt	$ 3,149,759	$ 3,214,427
Less debt issuance costs	(22,445)	(23,110)
Less debt discounts	(9,302)	(9,398)
Plus debt premiums	12,695	12,990
Total debt adjusted for debt issuance costs, discounts and premiums	3,130,707	3,194,909
Less current maturities	(93,351)	(93,039)
Long-term debt	$ 3,037,356	$ 3,101,870

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 secured revolving credit agreement, which is the lesser of $500 million or the amount available under our secured 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 borrowing on our consolidated statements of financial position.

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

	March 31, **2022**	December 31, **2021**
Commercial paper outstanding, net of discounts	$ 119,946	$ 49,997
Weighted average interest rate	0.70 %	0.19 %

At March 31, 2022, $380.0 million of the commercial paper back-up sublimit remained available under the 2018 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. Estimates of future expenditures for environmental reclamation obligations are not discounted.

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):

	Three Months Ended March 31, **2022**
Obligations at beginning of period	$ 90,281
Liabilities settled	(3,803)
Accretion expense	641
Total obligations at end of period	$ 87,119
Less current obligations at end of period	(5,769)
Long-term obligations at end of period	$ 81,350

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):

	March 31, **2022**	December 31, **2021**
Transmission easements	$ 18,857	$ 19,339
Operating lease liabilities - noncurrent	1,505	1,622
Contract liabilities (unearned revenue) - noncurrent	3,443	3,523
Customer deposits	8,095	9,287
Financial liabilities - reclamation	12,130	13,122
OATT deposits	11,461	24,327
Other	7,616	7,099
Total other deferred credits and other liabilities	$ 63,107	$ 78,319

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $27.8 million will be paid by us for these easements from 2022 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $18.9 and $19.3 million as of March 31, 2022 and December 31, 2021, respectively, which are recorded as other deferred credits and other liabilities.

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.

Financial liabilities - reclamation represents the financial obligation for our share of reclamation at San Juan Mine (related to our former ownership in the San Juan Generating Station) and our share of reclamation at Laramie River Station (related to our ownership share in MBPP).

OATT deposits primarily represent deposits that are received by us related to generator interconnection requests that may be returned if the project does proceed to completion.

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 at March 31, 2022, 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):

	Three Months Ended March 31, **2022**
Postretirement medical benefit obligation at beginning of period	$ 2,809
Service cost	—
Interest cost	9
Benefit payments (net of contributions by participants)	(162)
Postretirement medical benefit obligation at end of period	$ 2,656
Postemployment medical benefit obligation at end of period	392
Total postretirement and postemployment medical obligations at end of period	$ 3,048

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):

	Three Months Ended March 31, **2022**
Accumulated other comprehensive income at beginning of period	$ 3,580
Amortization of prior service credit into other income	(535)
Accumulated other comprehensive income at end of period	$ 3,045

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):

	Three Months Ended March 31, **2022**
Executive benefit restoration obligation at beginning of period	$ 9,852
Service cost	92
Interest cost	52
Executive benefit restoration at end of period	$ 9,996
Fair value of plan assets at beginning of period	$ 8,640
Employer contributions	303
Actual return on plan assets	$ (279)
Fair value of plan assets at end of period	$ 8,664
Net liability recognized at end of period	$ 1,332

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations. In December 2020, 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):

	Three Months Ended March 31, **2022**
Accumulated other comprehensive loss at beginning of period	$ (4,932)
Amortization of prior service cost into other income	283
Accumulated other comprehensive loss at end of period	$ (4,649)

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 42 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 March 31,	
	2022	**2021**
Non-member electric sales:		
Long-term contracts	$ 12,280	$ 8,706
Short-term contracts	10,664	8,634
Rate stabilization	7,883	20,834
Other	12,128	15,000
Total non-member electric sales and other operating revenue	$ 42,955	$ 53,174

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 $7.9 million of deferred membership withdrawal income for the three months ended March 31, 2022, and $20.8 million of deferred non-member electric sales revenue for the three months ended March 31, 2021, as directed by our Board. See Note 2 - Accounting for Rate Regulation.

Other operating revenue

Other operating revenue consists primarily of wheeling, transmission, and coal sales 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. Coal sales revenue results from the sale of coal from the Colowyo Mine and other locations 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.

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. Our consolidated statements of operations included an income tax expense of $18,000 for the three months ended March 31, 2022 and $109,000 for the comparable period in 2021.

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 current liabilities 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 $0.8 million for the three months ended March 31, 2022 and $1.0 million for the comparable period in 2021. 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 March 31, 2022, there were no arrangements accounted for as finance leases.

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

	March 31, **2022**	December 31, **2021**
Operating leases		
Operating lease right-of-use assets	$ 9,144	$ 9,081
Less: Accumulated amortization	(1,818)	(1,552)
Net operating lease right-of-use assets	$ 7,326	$ 7,529
Operating lease liabilities - current	$ (471)	$ (491)
Operating lease liabilities - noncurrent	(1,505)	(1,622)
Total operating lease liabilities	$ (1,976)	$ (2,113)
Operating leases		
Weighted average remaining lease term (years)	7.5	7.6
Weighted average discount rate	3.80 %	3.79 %

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

Year 1	$ 364
Year 2	384
Year 3	298
Year 4	480
Year 5	92
Thereafter	637
Total lease payments	$ 2,255
Less imputed interest	(279)
Total	$ 1,976

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 $1.8 million for the three months ended March 31, 2022 and 2021, 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 noncontrolling 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.

Executive Benefit Restoration Plan Trust

In December 2020, 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. 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):

	March 31, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 9,177	$ 8,664	$ 8,850	$ 8,640

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):

	March 31, 2022		December 31, 2021	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 603	$ 555	$ 597	$ 598

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 $84.6 million as of March 31, 2022 and $95.3 million as of December 31, 2021.

Debt

The fair values of long-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):

	March 31, 2022		December 31, 2021	
	Principal Amount	**Estimated Fair Value**	**Principal Amount**	**Estimated Fair Value**
Total long-term debt	$ 3,149,759	$ 3,371,589	$ 3,214,427	$ 3,759,991

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):

	March 31, **2022**	December 31, **2021**
Net electric plant	$ 735,601	$ 740,135
Noncontrolling interest	120,767	119,101
Long-term debt	255,587	300,220
Accrued interest	2,960	8,721

Our consolidated statements of operations include the following Springerville Partnership expenses for the three months ended March 31, 2022 and 2021 (dollars in thousands):

	Three Months Ended March 31,	
	2022	**2021**
Depreciation, amortization and depletion	$ 4,534	$ 4,534
Interest	4,704	5,185

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 noncontrolling 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 Tariff and Declaratory Order: 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 Member rates, transmission service, and our market based rates. We filed our tariff for wholesale electric service and transmission at FERC in December 2019. In addition, on December 23, 2019, we filed our Petition for Declaratory Order ("Jurisdictional PDO") with FERC, EL20-16-000, asking FERC to confirm our jurisdiction under the Federal Power Act ("FPA") and that FERC's jurisdiction preempts the jurisdiction of the Colorado Public Utilities Commission ("COPUC") to address any rate related issues, including the complaints filed by United Power, Inc. ("United Power") and La Plata Electric Association ("LPEA") with the COPUC.

On March 20, 2020, FERC issued orders regarding our Jurisdictional PDO and 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 Member rates and our transmission service rates prior to March 26, 2020. FERC also did not determine that our Utility Member 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.

On August 28, 2020, FERC issued an order ("August 28 Order") on rehearing related to our Jurisdictional PDO which modified its March 20, 2020 decision on our Jurisdictional PDO by finding exclusive jurisdiction over our contract termination payments related to our Utility Members and preempting the jurisdiction of the COPUC as of September 3, 2019. On December 16, 2020, United Power filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit Court of Appeals") related to FERC's August 28 Order. On March 30, 2022, oral arguments occurred before the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO.

Petitions for review related to our tariff filings, including our Utility Member rates, have been filed with the D.C. Circuit Court of Appeals by other parties. On March 28, 2022, an order was issued by the court to hold all the cases before the D.C. Circuit Court of Appeals in abeyance other than related to the Jurisdictional PDO, directing the parties to file motions to govern future proceedings by June 27, 2022.

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 being a settling party, the settlement resolved all issues set for hearing and settlement procedures related to our Utility Member rates. The settlement provides 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. The settlement rates will remain in effect at least through May 31, 2023 and during such time period, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule. We have also agreed to file a new Class A rate schedule after May 31, 2023 and prior to September 1, 2023. During the moratorium, we have established a rate design committee to oversee the development of the new rate. Three of the reserved issues are 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 will have prospective effect only, with the intent that any FERC rulings would be implemented in future rate filings. A hearing on the four reserved issued occurred in March 2022 before an administrative law judge at FERC and an initial decision is expected to be issued by an administrative law judge by the end of May 2022.

It is not possible to predict the outcome of the four reserved issues related to our member rates docket. In addition, we cannot predict the outcome of any petitions for review filed with the D.C. Circuit Court of Appeals.

LPEA and United Power COPUC Complaints: Pursuant to our Bylaws, a Utility 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 Utility Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. On November 5, 2019, LPEA filed a formal complaint with the COPUC alleging that we hindered LPEA's ability to seek withdrawal from us. On November 6, 2019, United Power filed a formal complaint with the COPUC, alleging that we hindered United Power's ability to explore its power supply options by either withdrawing from us or continuing as a Utility Member under a partial requirements contract. On November 20, 2019, the COPUC consolidated the two proceedings into one, 19F-0621E.

A hearing was held on May 18-20, 2020. On July 10, 2020, the administrative law judge issued a recommended decision, but the COPUC on its own motion stayed the recommended decision. On September 18, 2020, LPEA and United Power filed a Joint Motion to Lodge FERC's August 28 Order, and asserted additional corporate law arguments related to the legality of our addition of Non-Utility Members. On October 22, 2020, the COPUC determined that COPUC's jurisdiction over United Power and LPEA's complaints was preempted by FERC, the COPUC does not have jurisdiction over corporate law matters, and dismissed both complaints without prejudice. On January 27, 2021, United Power filed a Writ for Certiorari or Judicial Review, an appeal, in the Denver County District Court, 2021CV30325, of the COPUC's decision to dismiss United Power's complaint. On February 17, 2021, the Denver County District Court granted our unopposed motion to intervene as a defendant in United Power's appeal of the COPUC's dismissal. United Power, the COPUC, and us have all filed respective briefs with the court. The court heard oral arguments on September 17, 2021. It is not possible to predict the outcome of this matter.

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, including to add LPEA as an additional plaintiff, 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 and LPEA's claims. On July 30, 2021, the three Non-Utility Members filed a joint motion to dismiss all claims by United Power and LPEA 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 including seeking declamatory orders that the addition of the Non-Utility Members violated Colorado law, 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 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 the 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 and LPEA are entitled to any relief and requesting the court enter judgment of dismissal. We also asserted counterclaims against United Power and LPEA, and are seeking relief from United Power's and LPEA's breach of Tri-State's Bylaws and declaratory judgement 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 and LPEA filed a reply to our counterclaims asserting that we are not entitled to any relief on our counterclaims.

TAPP Complaint: On September 24, 2021, TransAmerican Power Products, Inc. ("TAPP") filed a complaint in Adams County District Court, 2021CV31089, against us alleging breach of contract and breach of implied covenant of good faith and fair dealing related to an invoice for TAPP's supply of materials for a transmission project. TAPP seeks damages of approximately $3 million. On November 9, 2021, we filed an answer and counterclaims against TAPP disputing any amount is owed to TAPP and seeking damages for TAPP's breach of contract. A jury trial is scheduled for April 2023. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

Basin Complaint: On December 17, 2021, Basin filed a complaint with the United States District Court District of North Dakota Eastern Division, 3:21-cv-00220-PDW-ARS, against us alleging that the filing of our modified contract termination payment tariff filed with FERC on September 1, 2021 constitutes a breach of our wholesale power contract with Basin for the Eastern Interconnection. On February 28, 2022, Basin filed a first amended compliant adding a new claim for anticipatory breach of contract. Basin seeks, among other things, for the court to require us to amend our modified contract termination payment tariff to exclude our Eastern Interconnection Utility Members. On March 29, 2022, we filed a motion to dismiss Basin's first amended complaint. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

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 4,440 MWs, of which approximately 1,366 MWs comes from renewables. We estimate that in 2021 over a third of the energy our Utility Members used came from clean sources.

We sold 4.3 million MWhs for the three months ended March 31, 2022, of which 90.3 percent was to Utility Members. Total revenue from electric sales was $316.3 million for the three months ended March 31, 2022 of which 89.2 percent was from Utility Member sales. Our results for the three months ended March 31, 2022 were primarily impacted by seasonal weather changes and rate stabilization measures.

- Utility Member electric sales increased $9.4 million, or 3.5 percent, primarily due to higher sales volume, but offset by 1.2 percent lower average price during the three months ended March 31, 2022 when compared to the same period in 2021. The decrease in average price was primarily due to our settlement agreement related to our Utility Member stated rate.
- Non-member electric sales increased $5.6 million, or 32.3 percent, primarily due to higher long-term and short-term market sales during the first quarter of 2022. While non-member electric sales increased in terms of MWhs, the average price for the three months ended March 31, 2022 was 20.0 percent lower when compared to the same period in 2021.
- Depreciation, amortization and depletion expense decreased $11.3 million, or 21.4 percent, primarily due to revisions to asset retirement obligations related to the South Taylor pit at the Colowyo Mine during the prior year.

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 March 31, 2022, 21 Utility Members have enrolled in this program with capacity totaling approximately 145 MWs of which 129 MWs are in operation.

Pursuant to our wholesale electric service contracts with our Utility Members, we convened a contract committee in 2019 and 2020, consisting of a representative from each Utility Member, to review the wholesale electric service contracts and to discuss alternative contracts for our Utility Members, including partial requirements contracts. Upon recommendations from the contract committee, our Board approved a community solar program, a partial requirements structure, including a buy-down payment methodology, and a methodology to calculate a contract termination payment. For further information see "Item 1 – BUSINESS – MEMBERS" in our annual report on Form 10-K for the year ended December 31, 2021.

Under the new partial requirements membership construct, Utility Members can 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. During our initial "open season" partial requirements nomination period that was completed in May 2021, three Utility Members were allocated an aggregate of 203 MWs of self-supply out of an available pool of 300 MWs. In January 2022, our Board approved an extension of the initial open season to offer the remaining 97 MWs of the 300 MWs of self-supply to the Utility Members who did not participate in 2021. Nominations for self-supply in the extended "open season" can be made in May 2022. No Utility Member has executed a partial requirements contract to become a Class B member.

The Utility Members that choose the partial requirements option will be obligated to make a buy-down payment to us. Our Board-approved buy-down payment methodology for a Class A member to become a Class B member was accepted by FERC in 2020, subject to refund. FERC referred it to FERC's hearing and settlement judge procedures. On April 28, 2022, we filed a proposed settlement agreement for approval with FERC related to our buy-down payment methodology. The proposed settlement agreement resolves all issue set for hearing and settlement procedures related to our buy-down payment methodology. Virtually all of the parties to the proceeding either support or do not oppose the resolution of the proceeding related to the buy-down payment methodology and the three Utility Members allocated self-supply during the initial "open season" are parties to the settlement. The settlement agreement resolves the level of the buy-down payment that a partial requirements Utility Member would pay us, and certain of the commercial terms and operational considerations applicable to the Utility Members that intend to become Class B partial requirements members. Class B members will continue to pay our Class A rate for load served by us and continue to purchase full-requirements transmission service from us.

Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us. 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 if a Utility Member elects 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 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. An in person hearing on our modified contract termination payment methodology began on May 3, 2022 before an administrative law judge at FERC with an initial decision expected to be issued by the administrative law judge by the end of July 2022. 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, 2021.

Three of our Utility Members, in December 2021, provided us conditional notices of their intent to withdraw from membership in us, including United Power and Northwest Rural Public Power District, with a January 1, 2024 withdrawal effective date. We filed certain answers to these conditional notices with FERC explaining that conditional notices are defective under the contract termination payment tariff and therefore a nullity. On April 21, 2022, FERC issued an order agreeing with our position that conditional notices are not permitted under our contract termination payment tariff and the conditional notices are invalid.

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. We are reviewing these notices.

In May 2020, United Power filed a complaint for declaratory judgement and damages against us 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 wholesale electric service contract with United Power. In July 2021, the court granted United Power's motion to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that our addition of the Non-Utility Members violated Colorado law. In March 2022, the court dismissed some of the claims against us in response to our July 2021 partial motion for summary judgement. In April 2022, we filed our answer to the remaining claims. 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. Over the past two years, 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 2024, 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, 2021.

Colorado Electric Resource Plan

In December 2020, we filed our first Phase I Electric Resource Plan under the 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 the addition of 2,050 MWs of additional renewable resources and more than 200 MWs of electric storage 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. On March 28, 2022, the administrative law judge for the COPUC recommended approval of the settlement agreement and the approval became effective on April 18, 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, 2021.

With the settlement agreement approved, we will begin Phase II of our 2020 Electric Resource Plan, and will solicit capacity and energy bids in May 2022, with a focus on projects that support emissions reductions. These projects would be scheduled to come online in 2025 and 2026. The bidding process is expected to close in July 2022, and we expect to file in December 2022 our implementation report with the COPUC.

On April 1, 2022, we made a filing with the COPUC that would, if approved, result in the retirement of our 85 MW natural-gas, combined-cycle Rifle Generating Station on or about October 6, 2022. Our Rifle Generating Station runs infrequently. The Rifle Generating Station came online in 1987 and we purchased the facility in 2002.

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 March 31, 2022, 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, 2021.

Factors Affecting Results

Master Indenture

As of March 31, 2022, we had approximately $2.9 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. As of December 31, 2021, our DSR was 1.19 and our ECR was 25.09 percent. 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 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 Utility 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 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. This policy establishes a goal of our Board on an annual or quarterly basis to either defer revenues and incomes as a regulatory liability or recognize previously deferred revenues and incomes (as available) in an amount that will result in a DSR equal to a DSR goal for the applicable year as set forth in the policy. As allowed by our Bylaws, the deferral or recognition of previously deferred revenues and income is for the purpose of stabilizing margins and limiting rate increases from year to year. This policy, subject to change by our Board, sets a DSR goal of 1.195 for the twelve months ended December 31, 2022 and a ECR goal of 24.0 percent as of December 31, 2022.

Rates and Regulation

On September 3, 2019, we became FERC jurisdictional for our Utility Member rates, transmission service, and our market based rates. In December 2019, we filed with FERC our tariff filings, including our stated rate cost of service filing, 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. FERC did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered FPA section 206 proceedings to determine the justness and reasonableness of our rates, including our Class A wholesale rate schedule (A-40) referenced below, and wholesale electric service contracts. On August 2, 2021, FERC approved our settlement agreement related to our Utility Member 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 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. In 2021 and 2022, 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 Member 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.

Our Class A rate schedule (A-40) was filed at FERC as a "stated rate." While our Board still has authority to determine our rates, those rates, including any change to the rate or rate structure, must be approved by FERC subject to outside comments. As part of the FERC approved settlement agreement, we and the settlement parties have agreed, with limited exceptions, to a moratorium on any filings related to our Class A rate schedule, including any rate increases to our Class A rate schedule, at least through May 31, 2023. A rate design committee consisting of a representative from each Utility Member is working on the development of a new rate to our Utility Members.

Our Board may from time to time, subject to FERC approval, create new regulatory assets or liabilities or modify the expected recovery period through rates of existing regulatory assets or liabilities. The amounts involved may be material. We continually evaluate options to achieve the goal to lower wholesale rates to our Utility Members.

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. Effective January 1, 2020, we adopted the normalization method for 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.

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;
- COVID-19 and governmental orders related to COVID-19; and
- economic conditions.

COVID-19 Impacts

We continue to experience decreased sales to our Utility Members and Utility Member revenue compared to prior to COVID-19 due to disruptions of operations from our Utility Members' industrial and commercial customers in the business of mineral extraction, natural gas, CO_2, oil production, or transportation of these. Outages at facilities of certain of these large customers has reduced demand from and energy sales to our Utility Members and such demand and energy sales have not returned. The extent to which the decreased sales may continue to impact our results of operations, including the long-term nature of the impacts, depends on numerous evolving factors, which are highly uncertain and difficult to predict.

Three months ended March 31, 2022 compared to three months ended March 31, 2021

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 March 31, 2022 and 2021 (dollars in thousands):

	Three Months Ended March 31,		Period-to-period Change	
	2022	**2021**	**Amount**	**Percent**
Operating revenues				
Utility Member electric sales	$ 282,247	$ 272,798	$ 9,449	3.5 %
Non-member electric sales	22,944	17,340	5,604	32.3 %
Rate stabilization	7,883	20,834	(12,951)	(62.2)%
Other	12,128	15,000	(2,872)	(19.1)%
Total operating revenues	$ 325,202	$ 325,972	$ (770)	(0.2)%
Energy sales (in MWh):				
Utility Member electric sales	3,857,646	3,708,132	149,514	4.0 %
Non-member electric sales	413,745	250,066	163,679	65.5 %
	4,271,391	3,958,198	313,193	7.9 %

- Utility Member electric sales revenue increased primarily due to higher sales volume, but offset by 1.2 percent lower average price during the three months ended March 31, 2022 when compared to the same period in 2021. The decrease in average price was primary due to our settlement agreement related to our Utility Member stated rate. See "Factors Affecting Results – Rates and Regulation.”
- Non-member electric sales increased primarily due to higher long-term and short-term market sales during the first quarter of 2022. Long-term sales increased 103,863 MWhs, or 150.3 percent, to 172,966 MWhs for the three months ended March 31, 2022 compared to 69,103 MWhs for the same period in 2021. Short-term market sales increased 59,816 MWhs, or 33.1 percent, to 240,779 MWhs for the three months ended March 31, 2022 compared to 180,963 MWs for the same period in 2021. While non-member electric sales increased in terms of MWhs, the average price for the three months ended March 31, 2022 was 20.0 percent lower when compared to the same period in 2021.
- In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $7.9 million of previously deferred membership withdrawal income during the three months ended March 31, 2022 compared to $20.8 million of previously deferred non-member electric sales revenue during the same period in 2021. In order to meet our 2022 financial goals, we expect to recognize additional previously deferred membership withdrawal income during the remainder of 2022.

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 March 31, 2022 and 2021 (dollars in thousands):

	Three Months Ended March 31,		Period-to-period Change	
	2022	2021	Amount	Percent
Operating expenses				
Purchased power	$ 87,300	$ 87,017	$ 283	0.3 %
Fuel	62,474	60,547	1,927	3.2 %
Production	37,796	40,901	(3,105)	(7.6)%
Transmission	47,182	44,671	2,511	5.6 %
General and administrative	20,273	14,587	5,686	39.0 %
Depreciation, amortization and depletion	41,475	52,755	(11,280)	(21.4)%
Coal mining	1,526	1,541	(15)	(1.0)%
Other	1,036	2,551	(1,515)	(59.4)%
Total operating expenses	$ 299,062	$ 304,570	$ (5,508)	(1.8)%

- General and administrative expense increased primarily due to lower recoveries of general and administrative costs from joint project activities, an increase in outside professional services and an overall increase in expenses related to general and administration labor and benefits.
- Depreciation, amortization and depletion expense decreased due to revisions to asset retirement obligation related to the South Taylor pit at the Colowyo Mine.

Financial condition as of March 31, 2022 compared to December 31, 2021

The principal changes in our financial condition from December 31, 2021 to March 31, 2022 were due to increases and decreases in the following:

Assets

- Cash and cash equivalents decreased $13.2 million, or 13.1 percent, to $87.4 million as of March 31, 2022 compared to $100.6 million as of December 31, 2021. Significant cash outlays for the three months ended March 31, 2022 included debt principal payments of $64.7 million (principally $44.4 million for the Springerville certificates and $9.1 million of CoBank and CFC debt), payment of property taxes of $13.0 million, and payments of accrued interest on long-term debt of $16.4 million. During the first quarter of 2022, we repurchased and cancelled $11.2 million of our First Mortgage Bonds, Series 2014E-1 and our First Mortgage Bonds, Series 2016A. These payments of cash were partially offset by an increase in commercial paper activity.
- Restricted cash and investments - current increased $16.7 million to $17.2 million as of March 31, 2022 compared to $0.5 million as of December 31, 2021. The increase was primarily due to $16.2 million that was deposited with our Master Indenture Trustee in March 2022 in advance of our April 1, 2022 First Mortgage Obligations, Series 2014B payment. In accordance with our Master Indenture, we are required to fund the trust account one day prior to debt service payments.
- Deposits and advances increased $6.3 million, or 18.3 percent, to $40.3 million as of March 31, 2022 compared to $34.0 million as of December 31, 2021. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These prepayments are being amortized to expense over the term of the related insurance, membership or license period.
- Regulatory assets decreased $6.3 million, or 1.0 percent, to $659.4 million as of March 31, 2022 compared to $665.7 million as of December 31, 2021. The change in regulatory assets was impacted by the deferral of the $3.7 million impairment loss related to Rifle Generating Station offset by $10.0 million of amortization of various regulatory assets to expense for recovery from our Utility Members in rates.

Liabilities

- Long-term debt decreased $64.5 million, or 2.1 percent, to $3.037 billion as of March 31, 2022 compared to $3.102 billion as of December 31, 2021 and current maturities of long-term debt increased $0.4 million, or 4.1 percent, to $93.4 million as of March 31, 2022 compared to $93.0 million as of December 31, 2021. The net decrease of $64.1 million was primarily due to debt payments of $64.7 million (principally $44.4 million for the Springerville

certificates and $9.1 million of CoBank and CFC debt). During the first quarter of 2022, we repurchased and cancelled $11.2 million of our First Mortgage Bonds, Series 2014E-1 and our First Mortgage Bonds, Series 2016A which resulted in a loss on extinguishment of debt of $0.3 million.
- Short-term borrowings increased $69.9 million, or 139.9 percent, to $119.9 million as of March 31, 2022 compared to $50.0 million as of December 31, 2021. The increase was due to commercial paper activity during the first quarter of 2022 related to early repurchase and cancellation of certain of our bonds.
- Accrued interest increased $18.1 million, or 70.4 percent, to $43.8 million as of March 31, 2022 compared to $25.7 million as of December 31, 2021. The increase was due to accruals for interest due in future periods of $34.5 million partially offset by interest payments of $16.4 million.
- Regulatory liabilities decreased $8.0 million, or 5.5 percent, to $138.0 million as of March 31, 2022 compared to $146.0 million as of December 31, 2021. The decrease was primarily due to the recognition of $7.9 million of previously deferred membership withdrawal income. In order to better align with our financial goals, we recognize deferred revenue and income on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2022.

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 March 31, 2022, we had $87.4 million in cash and cash equivalents. Our committed credit arrangement as of March 31, 2022 is as follows (dollars in thousands):

	Authorized Amount		Available March 31, 2022
2018 Revolving Credit Agreement	$ 650,000	(1)	$ 530,000

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

As of March 31, 2022, the secured 2018 Revolving Credit Agreement had aggregate commitments of $650 million, which included a swingline sublimit of $100 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $75 million of the letter of credit sublimit, and $380 million of the commercial paper back-up sublimit remained available as of March 31, 2022.

As of March 31, 2022, the 2018 Revolving Credit Agreement was secured under the Master Indenture and had a term extending through April 25, 2023. Funds advanced under the 2018 Revolving Credit Agreement would have been either LIBOR rate loans or base rate loans, at our option. LIBOR rate loans bore interest at the adjusted LIBOR rate for the term of the advance plus a margin (1.125 percent as of March 31, 2022) based on our credit ratings. Base rate loans bore interest at the alternate base rate plus a margin (0.125 percent as of March 31, 2022) based on our credit ratings. The alternate base rate was the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the one-month LIBOR rate plus 1.00 percent.

The 2018 Revolving Credit Agreement contained 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.

On April 25, 2022, the 2018 Revolving Credit Agreement was amended and restated by the 2022 Revolving Credit Agreement in the amount 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. The 2022 Revolving Credit Agreement has a maturity date of April 25, 2027, unless extended as provided therein. The 2022 Revolving Credit Agreement uses Term SOFR loans instead of LIBOR rate loans. The 2022 Revolving Credit Agreement contains financial covenants, including DSR and ECR requirements, similar to the 2022 Revolving Credit Agreement. 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 revolving credit facility, which was $500 million as of March 31, 2022 thereby providing 100 percent dedicated support for any commercial paper outstanding. As of March 31, 2022, we had $120 million of commercial paper outstanding (prior to netting discounts) and $380 million available on the commercial paper back-up sublimit.

We have from time to time purchased our outstanding debt through cash purchases and/or exchanges for other securities, in open market purchases, privately negotiated transactions or otherwise and may continue to seek to retire or purchase our outstanding debt 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 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.

Three months ended March 31, 2022 compared to three months ended March 31, 2021

Operating activities. Net cash provided by operating activities was $31.7 million for the three months ended March 31, 2022 compared to $76.0 million for the same period in 2021, a decrease in net cash provided by operating activities of $44.3 million. The decrease in net cash provided by operating activities was primarily due to an increase in prepayments of annual insurance, memberships and licenses, an increase in accounts receivable due to higher Utility Member electric sales in March 2022 compared to the same period in 2021, and timing of payment of trade payables and accrued expenses.

Investing activities. Net cash used in investing activities was $25.2 million for the three months ended March 31, 2022 compared to $32.5 million for the same period in 2021, a decrease in net cash used in investing activities of $7.3 million. The decrease in net cash used in investing activities was primarily due to 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 used in financing activities was $3.0 million for the three months ended March 31, 2022 compared to $61.3 million for the same period in 2021, a decrease in net cash used in financing activities of $58.3 million. The decrease in net cash used in financing activities was primarily due to an increase in short-term borrowings for the three month period ending March 31, 2022 compared to the same period in 2021 partially offset by higher principal payments of long-term debt.

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 2022 through 2026, we forecast that we may invest approximately $877 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, Utility Member load growth, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, 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 extensive federal, state and local environmental requirements. These environmental laws, rules and regulations are complex and change frequently. For a 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, 2021.

Rating Triggers

Our current senior secured ratings are "A3 (stable 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 revolving credit facility included a pricing grid related to the LIBOR or Term SOFR spread, as applicable, 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 be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include 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 similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

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, 2021.

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 are effective.

Changes in Internal Controls

There have been 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: May 9, 2022	By:	/s/ Duane Highley
		Duane Highley
		Chief Executive Officer
Date: May 9, 2022		/s/ Patrick L. Bridges
		Patrick L. Bridges
		Senior Vice President/Chief Financial Officer (Principal Financial Officer)