# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**WASHINGTON, D.C. 20549**

# FORM 10-Q

**(Mark One)**

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

**For the quarterly period ended September 30, 2021**
**OR**

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

**For the transition period from to**

**Commission File 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 SEPTEMBER 30, 2021

## GLOSSARY

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

| Abbreviations or Acronyms | Definition |
|---|---|
| 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) |
| DMEA | Delta-Montrose Electric Association |
| 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 |
| OSHA | Occupational Safety and Health Administration |
| Revolving Credit Agreement | Credit Agreement, dated as of April 25, 2018, between us and CFC, as administrative agent |
| 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 |
| 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)*

| | September 30, 2021 | December 31, 2020 |
|---|---|---|
| **ASSETS** | (unaudited) | |
| **Property, plant and equipment** | | |
| Electric plant | | |
| In service | $ 6,284,666 | $ 6,254,652 |
| Construction work in progress | 100,977 | 89,447 |
| Total electric plant | 6,385,643 | 6,344,099 |
| Less allowances for depreciation and amortization | (3,027,468) | (2,991,393) |
| Net electric plant | 3,358,175 | 3,352,706 |
| Other plant | 415,786 | 456,924 |
| Less allowances for depreciation, amortization and depletion | (160,357) | (133,012) |
| Net other plant | 255,429 | 323,912 |
| Total property, plant and equipment | 3,613,604 | 3,676,618 |
| **Other assets and investments** | | |
| Investments in other associations | 164,613 | 162,975 |
| Investments in and advances to coal mines | 2,448 | 2,799 |
| Restricted cash and investments | 4,241 | 4,682 |
| Other noncurrent assets | 16,500 | 14,889 |
| Total other assets and investments | 187,802 | 185,345 |
| **Current assets** | | |
| Cash and cash equivalents | 97,602 | 127,187 |
| Restricted cash and investments | 411 | 205 |
| Deposits and advances | 36,115 | 32,012 |
| Accounts receivable—Utility Members | 102,286 | 96,637 |
| Other accounts receivable | 23,694 | 20,570 |
| Electric plant held for sale | — | 4,877 |
| Coal inventory | 58,312 | 55,762 |
| Materials and supplies | 84,498 | 82,119 |
| Total current assets | 402,918 | 419,369 |
| **Deferred charges** | | |
| Regulatory assets | 675,964 | 710,268 |
| Prepayment—NRECA Retirement Security Plan | 17,460 | 21,490 |
| Other | 40,027 | 33,646 |
| Total deferred charges | 733,451 | 765,404 |
| **Total assets** | **$ 4,937,775** | **$ 5,046,736** |
| **EQUITY AND LIABILITIES** | | |
| **Capitalization** | | |
| Patronage capital equity | $ 1,009,213 | $ 978,519 |
| Accumulated other comprehensive loss | (5,940) | (5,714) |
| Noncontrolling interest | 117,334 | 114,851 |
| Total equity | 1,120,607 | 1,087,656 |
| Long-term debt | 3,110,546 | 3,200,181 |
| Total capitalization | 4,231,153 | 4,287,837 |
| **Current liabilities** | | |
| Utility Member advances | 19,091 | 16,592 |
| Accounts payable | 112,770 | 98,654 |
| Accrued expenses | 31,532 | 40,736 |
| Current asset retirement obligations | 6,511 | 11,044 |
| Accrued interest | 44,918 | 27,520 |
| Accrued property taxes | 26,939 | 32,794 |
| Current maturities of long-term debt | 91,165 | 87,587 |
| Total current liabilities | 332,926 | 314,927 |
| **Deferred credits and other liabilities** | | |
| Regulatory liabilities | 175,231 | 224,953 |
| Deferred income tax liability | 19,470 | 19,591 |
| Asset retirement and environmental reclamation obligations | 80,689 | 127,045 |
| Other | 78,765 | 54,600 |
| Total deferred credits and other liabilities | 354,155 | 426,189 |
| **Accumulated postretirement benefit and postemployment obligations** | 19,541 | 17,783 |
| **Total equity and liabilities** | **$ 4,937,775** | **$ 5,046,736** |

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| **Operating revenues** | | | | |
| Utility Member electric sales | $ 350,344 | $ 346,769 | $ 897,587 | $ 926,529 |
| Non-member electric sales | 44,451 | 38,606 | 118,770 | 71,044 |
| Other | 21,068 | 16,226 | 51,780 | 37,150 |
| | 415,863 | 401,601 | 1,068,137 | 1,034,723 |
| **Operating expenses** | | | | |
| Purchased power | 112,540 | 103,136 | 286,109 | 260,804 |
| Fuel | 76,332 | 65,061 | 182,749 | 165,679 |
| Production | 41,543 | 39,698 | 135,285 | 122,595 |
| Transmission | 50,152 | 43,989 | 136,771 | 127,175 |
| General and administrative | 15,916 | 17,081 | 42,400 | 49,337 |
| Depreciation, amortization and depletion | 44,990 | 45,775 | 144,228 | 137,110 |
| Coal mining | 1,492 | 4,200 | 3,999 | 8,021 |
| Other | 1,562 | 2,691 | 5,395 | 13,429 |
| | 344,527 | 321,631 | 936,936 | 884,150 |
| **Operating margins** | **71,336** | **79,970** | **131,201** | **150,573** |
| **Other income** | | | | |
| Interest | 897 | 959 | 2,681 | 3,248 |
| Capital credits from cooperatives | 59 | 1,186 | 4,334 | 4,674 |
| Other income | 1,358 | 197 | 3,247 | 348 |
| | 2,314 | 2,342 | 10,262 | 8,270 |
| **Interest expense** | | | | |
| Interest | 35,739 | 37,673 | 107,946 | 114,533 |
| Interest charged during construction | (861) | (1,460) | (2,839) | (5,022) |
| | 34,878 | 36,213 | 105,107 | 109,511 |
| **Income tax expense (benefit)** | 267 | (154) | 486 | (484) |
| **Net margins including noncontrolling interest** | 38,505 | 46,253 | 35,870 | 49,816 |
| **Net margin attributable to noncontrolling interest** | (1,765) | (1,424) | (5,176) | (4,164) |
| **Net margins attributable to the Association** | **$ 36,740** | **$ 44,829** | **$ 30,694** | **$ 45,652** |

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Net margins including noncontrolling interest | $ 38,505 | $ 46,253 | $ 35,870 | $ 49,816 |
| Other comprehensive income (loss): | | | | |
| Unrealized loss on securities available for sale | (15) | — | (56) | — |
| Amortization of actuarial loss on postretirement benefit obligation included in net margin | 220 | 177 | 951 | 1,287 |
| Unrecognized prior service cost | — | — | (1,121) | (7,373) |
| Other comprehensive income (loss) | 205 | 177 | (226) | (6,086) |
| Comprehensive income including noncontrolling interest | 38,710 | 46,430 | 35,644 | 43,730 |
| Net comprehensive income attributable to noncontrolling interest | (1,765) | (1,424) | (5,176) | (4,164) |
| **Comprehensive income attributable to the Association** | **$ 36,945** | **$ 45,006** | **$ 30,468** | **$ 39,566** |

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| **Patronage capital equity at beginning of period** | $ 972,473 | $ 984,221 | $ 978,519 | $ 1,031,063 |
| Net margins attributable to the Association | 36,740 | 44,829 | 30,694 | 45,652 |
| Retirement of patronage capital | — | — | — | (47,665) |
| **Patronage capital equity at end of period** | **1,009,213** | **1,029,050** | **1,009,213** | **1,029,050** |
| **Accumulated other comprehensive loss at beginning of period** | (6,145) | (7,781) | (5,714) | (1,518) |
| Unrealized loss on securities available for sale | (15) | — | (56) | — |
| Amortization of prior service cost | 220 | 177 | 951 | 1,287 |
| Unrecognized prior service cost | — | — | (1,121) | (7,373) |
| **Accumulated other comprehensive loss at end of period** | **(5,940)** | **(7,604)** | **(5,940)** | **(7,604)** |
| **Noncontrolling interest at beginning of period** | 115,569 | 113,189 | 114,851 | 111,717 |
| Net comprehensive income attributable to noncontrolling interest | 1,765 | 1,424 | 5,176 | 4,164 |
| Equity distribution to noncontrolling interest | — | (1,188) | (2,693) | (2,456) |
| **Noncontrolling interest at end of period** | **117,334** | **113,425** | **117,334** | **113,425** |
| **Total equity at end of period** | **$ 1,120,607** | **$ 1,134,871** | **$ 1,120,607** | **$ 1,134,871** |

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

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

| | Nine Months Ended September 30, 2021 | Nine Months Ended September 30, 2020 |
|---|---|---|
| **Operating activities** | | |
| Net margins including noncontrolling interest | $ 35,870 | $ 49,816 |
| Adjustments to reconcile net margins to net cash provided by operating activities: | | |
| Depreciation, amortization and depletion | 144,228 | 137,110 |
| Amortization of NRECA Retirement Security Plan prepayment | 4,029 | 4,029 |
| Amortization of debt issuance costs | 1,867 | 1,832 |
| Impairment loss | — | 259,761 |
| Deferred impairment loss and other closure costs | — | (268,163) |
| Recognition of deferred revenue | (49,364) | — |
| Deferred membership withdrawal income | — | 110,165 |
| Deposits associated with generator interconnection requests | 17,130 | — |
| Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions | (1,180) | 2,813 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (12,991) | 5,844 |
| Coal inventory | (2,064) | (5,688) |
| Materials and supplies | (1,977) | 290 |
| Accounts payable and accrued expenses | 27,258 | 9,337 |
| Accrued interest | 17,397 | 16,113 |
| Accrued property taxes | (5,856) | (1,043) |
| Other | (3,654) | (16,323) |
| **Net cash provided by operating activities** | **170,693** | **305,893** |
| **Investing activities** | | |
| Purchases of plant | (83,405) | (100,821) |
| Sale of electric plant | — | 26,000 |
| Changes in deferred charges | (15,734) | (4,532) |
| Proceeds from other investments | 72 | 68 |
| **Net cash used in investing activities** | **(99,067)** | **(79,285)** |
| **Financing activities** | | |
| Changes in Member advances | 2,499 | (1,520) |
| Payments of long-term debt | (87,138) | (277,119) |
| Proceeds from issuance of long-term debt | — | 425,000 |
| Debt issuance costs | — | (637) |
| Change in short-term borrowings, net | — | (252,323) |
| Retirement of patronage capital | (13,705) | (60,991) |
| Equity distribution to noncontrolling interest | (2,693) | (2,456) |
| Other | (409) | (279) |
| **Net cash used in financing activities** | **(101,446)** | **(170,325)** |
| **Net increase (decrease) in cash, cash equivalents and restricted cash and investments** | **(29,820)** | **56,283** |
| **Cash, cash equivalents and restricted cash and investments – beginning** | **132,074** | **113,768** |
| **Cash, cash equivalents and restricted cash and investments – ending** | **$ 102,254** | **$ 170,051** |
| **Supplemental cash flow information:** | | |
| Cash paid for interest | $ 89,119 | $ 97,218 |
| Cash paid for income taxes | $ — | $ — |
| **Supplemental disclosure of noncash investing and financing activities:** | | |
| Change in plant expenditures included in accounts payable | $ 2,730 | $ 2,217 |

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

# Tri-State Generation and Transmission Association, Inc.
# Notes to Unaudited Consolidated Financial Statements
# For the Three and Nine Months Ended September 30, 2021 and 2020

## 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, 2020 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. Our consolidated financial position as of September 30, 2021, results of operations for the three and nine months ended September 30, 2021 and 2020, and cash flows for the nine months ended September 30, 2021 and 2020 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. In August 2021, Thermo Cogeneration Partnership, LP and its related entities merged into Tri-State. There was no impact to our consolidated financial statements as a result of this merger.

*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.

Effective August 1, 2021, our ownership share in MBPP increased to 28.5 percent due to our acquisition of Wyoming Municipal Power Agency's ownership share in MBPP. The purchase represents an additional 1.37 percent undivided ownership interest in MBPP, which includes transmission and water rights and approximately 23 megawatts of generation.

Our share in each jointly owned facility is as follows as of September 30, 2021 (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 % | $ 391,695 | $ 253,183 | $ 790 |
| MBPP - Laramie River Station | 28.50 % | 523,438 | 334,827 | 3,453 |
| Total | | $ 915,133 | $ 588,010 | $ 4,243 |

*Recently Adopted Accounting Pronouncements*

On December 18, 2019, the Financial Accounting Standards Board issued ASU 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes, which may impact both interim and annual reporting periods. This guidance is required to be adopted by public filers for years beginning after December 15, 2020. Under previous guidance, when there was a change in tax law (such as a change in the statutory tax rate), ASC 740 required the impact on deferred taxes to be recognized in the reporting period that included the enactment date. However, the interim period guidance under ASC 740-270 required that the effect of a change in tax rate be recognized in the estimated annual effective tax rate at enactment date or the effective date, whichever occurred later. Thus, in situations where a rate change was enacted in one interim period but effective in another interim period, complexities arose with respect to deferred tax balances and taxes payable. ASU 2019-12 modifies the previous approach so that changes in tax law should be reflected in the estimated annual rate in the period of enactment. This better aligns the interim reporting framework with the overall guidance with respect to changes in tax law. As described in Note 13 - Income Taxes, federal legislation has been proposed to increase the federal corporate income tax rate. If that were to occur, we would report the impact pursuant to ASU 2019-12. We do not anticipate having any other material financial reporting impacts caused by ASU 2019-12.

**NOTE 2 – ACCOUNTING FOR RATE REGULATION**

In accordance with the accounting requirements related to regulated operations, some revenues and expenses have been deferred at the discretion of our Board of Directors ("Board"), subject to FERC approval, if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs that we expect to recover from our Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Utility Members based on rates approved by the applicable authority. Expected recovery of deferred costs and returning deferred credits are based on specific ratemaking decisions by FERC or precedent for each item. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery through rates.

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

| | September 30, 2021 | December 31, 2020 |
|---|---|---|
| **Regulatory assets** | | |
| Deferred income tax expense (1) | $ 19,035 | $ 19,641 |
| Deferred prepaid lease expense – Springerville Unit 3 Lease (2) | 79,706 | 81,424 |
| Goodwill – J.M. Shafer (3) | 44,159 | 46,296 |
| Goodwill – Colowyo Coal (4) | 35,386 | 36,161 |
| Deferred debt prepayment transaction costs (5) | 125,831 | 132,302 |
| Deferred Holcomb expansion impairment loss (6) | 85,313 | 88,819 |
| Unrecovered plant (7) | 286,534 | 305,625 |
| Total regulatory assets | 675,964 | 710,268 |
| **Regulatory liabilities** | | |
| Interest rate swap - realized gain (8) and other | 2,935 | 3,293 |
| Deferred revenues (9) | 14,353 | 63,717 |
| Membership withdrawal (10) | 157,943 | 157,943 |
| Total regulatory liabilities | 175,231 | 224,953 |
| Net regulatory asset | $ 500,733 | $ 485,315 |

(1) Represents a regulatory asset or liability associated with deferred income tax expense that is expected to result in income taxes payable in future periods. 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.

(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 Thermo Cogeneration Partnership, LP 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 and Escalante Generating Stations. The deferred impairment loss for Nucla Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $9.1 million annually through December 2022 and recovered from our Utility Members through rates. The deferred impairment loss for Escalante Generating Station is being amortized to depreciation, amortization and depletion expense in the amount of $11.3 million annually over the 25-year period ending in December 2045, which was the depreciable life of Escalante Generating Station, and recovered from our Utility Members through rates. The annual amortization approximates the former annual Escalante Generating Station depreciation for the remaining life of the asset.

(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 deferral of the recognition of non-member electric sales revenues. These deferred non-member electric sales revenues will be refunded to Utility Members as part of our rate stabilization measures when recognized in non-member electric sales revenue in future periods.

(10) Represents the deferral of the recognition of other income related to the withdrawal of former Utility Members from membership in us. The total deferred membership withdrawal income will be refunded to Utility Members as part of our rate stabilization measures when recognized in other income in future periods.

**NOTE 3 – INVESTMENTS IN OTHER ASSOCIATIONS**

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

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Basin Electric Power Cooperative | $ 118,295 | $ 118,295 |
| National Rural Utilities Cooperative Finance Corporation - patronage capital | 12,076 | 11,933 |
| National Rural Utilities Cooperative Finance Corporation - capital term certificates | 15,149 | 15,221 |
| CoBank, ACB | 12,985 | 11,141 |
| Other | 6,108 | 6,385 |
| Investments in other associations | $ 164,613 | $ 162,975 |

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the nine months ended September 30, 2021 or during 2020.

**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):

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Cash and cash equivalents | $ 97,602 | $ 127,187 |
| Restricted cash and investments - current | 411 | 205 |
| Restricted cash and investments - noncurrent | 4,241 | 4,682 |
| Cash, cash equivalents and restricted cash and investments | $ 102,254 | $ 132,074 |

## NOTE 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

*Accounts Receivable*

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 12 – Revenue.

*Contract liabilities (unearned revenue)*

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. During the nine months ended September 30, 2021, we recognized $0.4 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Accounts receivable - Utility Members | $ 102,286 | $ 96,637 |
| | | |
| Other accounts receivable - trade: | | |
| Non-member electric sales | 8,277 | 5,231 |
| Other | 12,771 | 9,785 |
| Total other accounts receivable - trade | 21,048 | 15,016 |
| Other accounts receivable - nontrade | 2,646 | 5,554 |
| Total other accounts receivable | $ 23,694 | $ 20,570 |
| | | |
| Contract liabilities (unearned revenue) | $ 5,590 | $ 6,025 |

## NOTE 6 – OTHER DEFERRED CHARGES

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Preliminary surveys and investigations | $ 11,371 | $ 12,886 |
| Advances to operating agents of jointly owned facilities | 7,770 | 2,071 |
| Operating lease right-of-use assets | 7,505 | 7,985 |
| Other | 13,381 | 10,704 |
| Total other deferred charges | $ 40,027 | $ 33,646 |

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 $3.1 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 $13.9 million as of September 30, 2021. 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.

We have a secured revolving credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC"), as lead arranger and administrative agent, in the amount of $650 million ("Revolving Credit Agreement") that expires on April 25, 2023 and includes 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 September 30, 2021, we had $650.0 million in availability under the Revolving Credit Agreement.

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Total debt | $ 3,221,577 | $ 3,308,715 |
| Less debt issuance costs | (23,723) | (25,590) |
| Less debt discounts | (9,464) | (9,659) |
| Plus debt premiums | 13,321 | 14,302 |
| Total debt adjusted for debt issuance costs, discounts and premiums | 3,201,711 | 3,287,768 |
| Less current maturities | (91,165) | (87,587) |
| Long-term debt | $ 3,110,546 | $ 3,200,181 |

**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 Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our Revolving Credit Agreement. As of September 30, 2021 and December 31, 2020, we had no commercial paper outstanding.

At September 30, 2021, $500.0 million of the commercial paper back-up sublimit remained available under the 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 2019 with the other remaining pits still being actively mined.

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

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

| | Nine Months Ended September 30, **2021** |
|---|---|
| Obligations at beginning of period | $ 138,089 |
| Liabilities incurred | 500 |
| Liabilities settled | (4,384) |
| Accretion expense | 1,913 |
| Change in estimate | (48,918) |
| Total obligations at end of period | $ 87,200 |
| Less current obligations at end of period | (6,511) |
| Long-term obligations at end of period | $ 80,689 |

During 2021, we recorded a reduction of the Colowyo Mine reclamation liability of $43.8 million. This reduction was primarily related to a change in the mine plan of South Taylor pit at the Colowyo Mine. After obtaining regulatory approval, the South Taylor pit life was extended through 2027 to mine the highwall, which resulted in a lower estimated obligation at the end of the mining period. The West pit is currently in final reclamation. In 2019, we recorded an additional reclamation obligation liability of $22.4 million due to anticipated revision to the New Horizon Mine reclamation plan to accommodate an alternative post mine land use as necessary for final mine reclamation. We continue to evaluate the Colowyo Mine and New Horizon Mine post reclamation obligations and will make adjustments to these obligations as needed.

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

## NOTE 10 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| Transmission easements | $ 19,531 | $ 19,983 |
| Operating lease liabilities - noncurrent | 1,675 | 1,590 |
| Contract liabilities (unearned revenue) - noncurrent | 3,634 | 3,702 |
| Customer deposits | 8,860 | 7,712 |
| Financial liabilities - reclamation | 12,266 | 12,081 |
| Deposits associated with generator interconnection requests | 22,709 | — |
| Other | 10,090 | 9,532 |
| Total other deferred credits and other liabilities | $ 78,765 | $ 54,600 |

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $29.2 million will be paid by us for these easements from 2021 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $19.5 and $20.0 million as of September 30, 2021 and December 31, 2020, 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.

## 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 postemployment medical benefits to employees on long-term disability. The plans were unfunded at September 30, 2021, 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 postemployment medical benefit obligations are determined annually (during the fourth quarter) by an independent actuary and are included in accumulated postretirement benefit and postemployment obligations on our consolidated statements of financial position as follows (dollars in thousands):

| | Nine Months Ended September 30, **2021** |
|---|---|
| Postretirement medical benefit obligation at beginning of period | $ 9,985 |
| Service cost | 451 |
| Interest cost | 194 |
| Benefit payments (net of contributions by participants) | (444) |
| Postretirement medical benefit obligation at end of period | $ 10,186 |
| Postemployment medical benefit obligation at end of period | 419 |
| Total postretirement and postemployment medical obligations at end of period | $ 10,605 |

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

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

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

| | Nine Months Ended September 30, **2021** |
|---|---|
| Accumulated other comprehensive loss at beginning of period | $ (841) |
| Amortization of prior service credit into other income | (59) |
| Accumulated other comprehensive loss at end of period | $ (900) |

*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 currently 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. As of April 30, 2021, the plans ceased to add new participants hired after this date.

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

| | Nine Months Ended September 30, **2021** |
|---|---|
| Executive benefit restoration obligation at beginning of period | $ 7,379 |
| Service cost | 270 |
| Interest cost | 165 |
| Actuarial loss | 1,121 |
| Executive benefit restoration at end of period | $ 8,935 |
| Fair value of plan assets at beginning of period | $ 6,955 |
| Employer contributions | 1,209 |
| Actual return on plan assets | $ 95 |
| Fair value of plan assets at end of period | $ 8,259 |
| Net liability recognized at end of period | $ 676 |

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):

| | Nine Months Ended September 30, **2021** |
|---|---|
| Accumulated other comprehensive loss at beginning of period | $ (4,873) |
| Amortization of prior service cost into other income | 698 |
| Amortization of actuarial loss | 171 |
| Curtailment and settlement | 141 |
| Unrecognized actuarial loss | (1,121) |
| Accumulated other comprehensive loss at end of period | $ (4,984) |

**NOTE 12 – REVENUE**

*Revenue from Contracts with Customers*

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| Non-member electric sales: | | | | |
| Long-term contracts | $ 11,380 | $ 9,423 | $ 30,179 | $ 32,817 |
| Short-term contracts | 24,496 | 29,183 | 39,226 | 38,227 |
| Recognition of deferred revenue | 8,575 | — | 49,365 | — |
| Other | 21,068 | 16,226 | 51,780 | 37,150 |
| Total non-member electric sales and other operating revenue | $ 65,519 | $ 54,832 | $ 170,550 | $ 108,194 |

*Non-member electric sales*

Revenues from 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.

*Other operating revenue*

Other operating revenue consists primarily of wheeling, transmission, and coal sales revenue. Other operating revenue also includes revenue we receive from two of 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 $0.5 million for the nine months ended September 30, 2021 and an income tax benefit of $0.5 million for the comparable period in 2020.

Federal legislation has been proposed that contains provisions that may impact us. However, enactment of legislative proposals remains uncertain. We are monitoring developments.

**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 September 30, 2021 and $1.2 million for the comparable period in 2020. Rent expense for all short-term and long-term operating leases was $2.6 million for the nine months ended September 30, 2021 and $2.8 million for the comparable period in 2020. Rent expense is included in various categories of operating expenses on our consolidated statements of operations based on the type and purpose of the lease. As of September 30, 2021, there were no arrangements accounted for as finance leases.

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

| | September 30, **2021** | December 31, **2020** |
|---|---|---|
| **Operating leases** | | |
| Operating lease right-of-use assets | $ 9,402 | $ 9,223 |
| Less: Accumulated amortization | (1,897) | (1,238) |
| Net operating lease right-of-use assets | $ 7,505 | $ 7,985 |
| | | |
| Operating lease liabilities - current | $ (487) | $ (526) |
| Operating lease liabilities - noncurrent | (1,675) | (1,590) |
| Total operating lease liabilities | $ (2,162) | $ (2,116) |
| | | |
| **Operating leases** | | |
| Weighted average remaining lease term (years) | 7.6 | 7.6 |
| Weighted average discount rate | 3.85 % | 3.84 % |

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

| | |
|---|---|
| Year 1 | $ 466 |
| Year 2 | 352 |
| Year 3 | 315 |
| Year 4 | 196 |
| Year 5 | 91 |
| Thereafter | 923 |
| Total lease payments | $ 2,343 |
| Less imputed interest | (181) |
| Total | $ 2,162 |

*Leasing Arrangements As Lessor*

We have lease agreements as lessor for certain operational assets. The revenue from these lease agreements of $2.2 million and $1.8 million for the three months ended September 30, 2021 and 2020, respectively, and $5.7 million and $5.0 million for the nine months ended September 30, 2021 and 2020 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):

| | September 30, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| | Cost | Estimated Fair Value | Cost | Estimated Fair Value |
| EBR Trust investments | $ 8,259 | $ 8,147 | $ 6,955 | $ 6,955 |

*Marketable Securities*

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

| | September 30, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| | Cost | Estimated Fair Value | Cost | Estimated Fair Value |
| Marketable securities | $ 520 | $ 561 | $ 491 | $ 478 |

*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 $71.8 million as of September 30, 2021 and $94.6 million as of December 31, 2020.

*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):

| | September 30, 2021 | | December 31, 2020 | |
|---|---|---|---|---|
| | Principal Amount | Estimated Fair Value | Principal Amount | Estimated Fair Value |
| Total long-term debt | $ 3,221,577 | $ 3,809,555 | $ 3,308,715 | $ 3,908,497 |

## 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 and also entities for which we are not the primary beneficiary and therefore do not consolidate.

***Consolidated Variable Interest Entity***

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

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

| | September 30, 2021 | December 31, 2020 |
|---|---|---|
| Net electric plant | $ 744,670 | $ 758,273 |
| Noncontrolling interest | 117,334 | 114,852 |
| Long-term debt | 300,507 | 342,355 |
| Accrued interest | 3,488 | 9,942 |

Our consolidated statements of operations include the following Springerville Partnership expenses for the three and nine months ended September 30, 2021 and 2020 (dollars in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| Depreciation, amortization and depletion | $ 4,534 | $ 4,535 | $ 13,603 | $ 13,603 |
| Interest | 4,951 | 5,646 | 15,092 | 17,157 |

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 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 206 proceedings to determine the justness and reasonableness of our rates and wholesale electric service contracts. The tariff rates were referred to administrative law judges to encourage settlement of material issues and to hold hearings if settlements were not reached. Any refunds to the applicable tariff rates would only apply for sales after March 26, 2020. On April 30, 2021, we filed a proposed settlement agreement with FERC related to our Utility Member stated rate for approval, as further discussed below. On October 22, 2021, we filed a proposed settlement agreement with FERC related to our transmission service rates for approval, as further discussed below. FERC’s March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceeding at the COPUC stating the proceeding was not currently preempted.

On July 17, 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 March 20, 2020 order related to our Utility Member rates and such matter is being held in abeyance pending resolution of the Jurisdictional PDO appeal discussed below.

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 by finding exclusive jurisdiction over our contract termination payments 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 D.C. Circuit Court of Appeals related to FERC’s August 28 Order. Petitions for review related to both the Jurisdictional PDO and tariff filings have been filed with the D.C. Circuit Court of Appeals by other parties.

On September 29, 2021, 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 December 20, 2021. FERC, United Power, and the other parties reached agreement on the procedures and schedule for the Jurisdictional PDO. On June 7, 2021, United Power filed its brief with the D.C. Circuit Court of Appeals regarding the

Jurisdictional PDO. On September 27, 2021, FERC filed its brief with the D.C. Circuit Court of Appeals regarding the Jurisdictional PDO.

On April 30, 2021, we filed a proposed settlement agreement for approval with FERC 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 resolves 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 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 will establish 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. On June 30, 2021, the Chief Judge terminated the settlement judge procedures for our member rates docket. On August 2, 2021, FERC approved this settlement agreement. On September 1, 2021, we filed a motion with FERC to set a procedure schedule for the four reserved issues. On November 2, 2021, FERC issued an order rejecting the procedural schedule and returning the reserved issues to settlement and/or hearing procedures before an administrative law judge.

On October 22, 2021, we filed a proposed settlement agreement for approval with FERC related to our transmission service rates, including our open access transmission tariff and annual transmission revenue requirements. The proposed settlement resolves all issues set for hearing and settlement procedures related to our transmission service rates. The proposed settlement agreement provides for us to refund amounts collected more than the amounts agreed to in the proposed settlement agreement beginning March 26, 2020 upon FERC’s approval of the settlement agreement. We also filed a motion with FERC’s Chief Judge seeking authorization to implement our reduced transmission service rates and annual transmission revenue requirements for the 2021 rate year beginning on October 1, 2021 pending FERC’s approval of the proposed settlement agreement. In connection with the proposed settlement, our other revenue and results of operations does not include our estimate of revenue that is expected to be refunded. Such amount is being held in reserve.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020 on outstanding issues, if FERC will approve our proposed settlement agreement filed on October 22, 2021 related to our transmission service rates and tariff, or the outcome of the four reserved issues related to our member rates docket. In addition, we cannot predict the outcome of the 206 proceedings or 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 asserting 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 in 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 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, the April 2020 Board approvals related to a "Make-Whole" methodology for a contract termination payment and buy-down payment formula are also void, that we have breached the wholesale electric service contract with United Power, and that we and our three Non-Utility Members conspired to deprive the COPUC of jurisdiction over the contract termination payment of our Colorado Utility Members. On June 20, 2020, we filed our answer denying United Power's allegations and request for relief, and asked the court to dismiss United Power's claims. We asserted counterclaims against United Power, and are seeking relief from United Power's breach of our Bylaws and declaratory judgement that the April 2019 Bylaws amendment and the April 2020 Board approvals related to a "Make-Whole" methodology for a contract termination payment and buy-down payment formula are valid. On June 20, 2020, the three Non-Utility Members filed a joint motion to dismiss. On December 10, 2020, the Non-Utility Members motion to dismiss was granted. On December 23, 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff and to add a claim that that our addition of the Non-Utility Members violated Colorado law. 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 and to amend its claims as to our three Non-Utility Members. On July 30, 2021, we filed a partial motion to dismiss a majority of United Power's and LPEA's claims, including claims related to the April 2019 Bylaws amendment, the April 2020 Board approvals, and that we conspired with our Non-Utility Members. 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. It is not possible to predict the outcome of this matter or whether we will incur any liability in connection with this matter.

*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. We dispute that any amount is owed TAPP. 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 4,197 MWs, of which approximately 1,166 MWs comes from renewables. In 2020, we estimate that nearly a third of the energy delivered by us and our Utility Members to our Utility Members' customers came from non-carbon emitting resources.

We sold 13.2 million MWhs for the nine months ended September 30, 2021, of which 91.1 percent was to Utility Members. Total revenue from electric sales was $1.016 billion for the nine months ended September 30, 2021 of which 88.3 percent was from Utility Member sales. Our results for the nine months ended September 30, 2021 were primarily impacted by seasonal weather changes and rate stabilization measures.

- Utility Member electric sales decreased $28.9 million, or 3.1 percent, primarily due to reduced membership and a rate reduction in our Utility Member stated rate.
- Non-member electric sales increased $47.7 million, or 67.2 percent, primarily due to rate stabilization measures. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021.
- Purchased power expense increased $25.3 million, or 9.7 percent, primarily due to decreased generation from our generating resources because of maintenance activities and favorable market conditions for purchasing power.
- Depreciation, amortization and depletion expense increased $7.1 million, or 5.2 percent, primarily due to revisions to asset retirement obligations related to the South Taylor pit at the Colowyo Mine during the prior year.

### Recent Developments

At our August 2021 annual meeting of our Members, our Members approved amendments to our Bylaws to limit the number of Non-Utility Members to no greater than ten. We currently have three Non-Utility Members.

Following our August 2021 annual meeting of our Members, our Board elected the officers of our Board. Tim Rabon, who represents Otero County Electric Cooperative, Inc., was elected Chairman and President of our Board. Tim Rabon was previously the Vice-Chairman of our Board. Rick Gordon, who served as chair since 2010, did not seek reelection, but will remain on our Board.

In August 2021, the entities, including Thermo Cogeneration Partnership, LP, that own J.M. Shafer Generation Station were merged into Tri-State. J.M. Shafer Generation Station is our 272 MW, natural gas fired, combined-cycle generating facility located near Fort Lupton, Colorado.

**Our Bylaws and Wholesale Electric Service Contracts**

Our Bylaws require each Utility Member, unless otherwise specified in a written agreement or the terms of the Bylaws, to purchase from us electric power and energy as provided in the Utility Member's contract with us. This contract is the wholesale electric service contract with each Utility Member, which is an all-requirements contract. Each wholesale electric service contract obligates us to sell and deliver to the Utility Member, and obligates the Utility Member to purchase and receive, at least 95 percent of its electric power requirements from us. Our wholesale electric service contracts with our 42 Utility Members extend through 2050. Each Utility Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Utility Member. As of September 30, 2021, 20 Utility Members have enrolled in this 5 percent self-supply provision with capacity totaling approximately 145 MWs of which 126 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 “Make-Whole” methodology for a contract termination payment. Each of these items recommended by the contract committee representing our Utility Members were filed with FERC for approval in 2020. FERC accepted each of these items, subject to refund, and referred them to FERC's hearing and settlement judge procedures. 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 first "open season" partial requirements nomination period that was completed in May 2021, three Utility Members submitted nominations for an aggregate of 203 MWs of self-supply out of an available pool of 300 MWs. For further information see “Item 1 – BUSINESS – MEMBERS – Contract Committee” in our annual report on Form 10-K for the year ended December 31, 2020.

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. In April 2020, our Board approved a “Make-Whole” methodology for a contract termination payment designed to leave remaining Utility Members in the same economic position after a Utility Member terminates its wholesale electric service contract as the remaining Utility Members would have been had the Utility Member not terminated. In April 2020, we filed with FERC our Board approved contract termination payment methodology. In June 2020, FERC accepted our contract termination payment methodology and referred it to FERC’s hearing and settlement judge procedures. In late 2020, certain Utility Members formally requested a contract termination payment amount for planning purposes. In January 2021, we notified each of these Utility Members that the contract termination payment calculation is time-intensive. In late February 2021, seven of our Utility Members filed a complaint with FERC seeking the contract termination payment amount on an expedited basis. In March 2021, we filed a motion to dismiss and answer.

In June 2021, FERC issued a show cause order to us regarding our contract termination payment calculation and specifically regarding procedures for our Utility Members to obtain such calculations prior to making their termination decision. In July 2021, we filed our response to the show cause order and described a plan to file a simpler and more transparent modified contract termination methodology approved by our Board. On September 2, 2021, we filed both a response to the show cause order and a modified contract termination payment methodology. The modified methodology eliminates our Board discretion over a Utility Member's withdrawal and provides a clear procedure and direct path to obtain a calculation without any delay or fees. The modified methodology continues to protect the financial interests of our remaining Utility Members if a Utility Member elects to withdraw. Our September 2, 2021 filing also included the contract termination payment amount for each of our Utility Members under the modified methodology assuming a January 1, 2024 withdraw date. A number of our Utility Members and other parties have intervened in both the show cause order and our filing of a modified contract termination payment methodology. A majority of our Utility Members voted in favor of our modified methodology and seven of such Utility Members filed comments with FERC in support of our filing. Four of our Utility Members filed a protest. On October 29, 2021, FERC accepted our modified contract termination payment methodology, effective November 1, 2021, subject to refund. FERC set the matter for hearing and instituted a concurrent section 206 proceeding to determine the justness and reasonableness of our modified methodology. FERC did not consolidate our modified contract termination payment methodology with FERC's July 2021 show cause order nor with the on-going consolidated hearing and settlement procedures for our buy-down payment methodology and our original contract termination payment methodology filed in 2020. No Utility Member has requested to terminate its wholesale electric service contract with us or to withdraw from membership.

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 the wholesale electric service contract with United Power. In December 2020, United Power sought to amend its May 2020 compliant to add LPEA as an additional plaintiff. In July 2021, the court granted United Power's motion to amend its May 2020 complaint. In July 2021, we filed a partial motion to dismiss the amended May 2020 complaint. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.

**Responsible Energy Plan**

In January 2020, we announced our Responsible Energy Plan, which will advance our clean energy transition. 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.

As part of our Responsible Energy Plan, in January 2020, we announced the early retirements of Craig Station by 2030 and Escalante Station by the end of 2020. In connection with such early retirements, our Board continues to evaluate the creation of additional regulatory assets and use of regulatory liabilities to achieve the goal to lower wholesale rates to our Utility Members. A creation of regulatory assets to defer expenses associated with these early retirements or the utilization of regulatory liabilities would require FERC approval.

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, 2020.

**COVID-19 Impacts**

We continue to experience decreased sales to our Utility Members and Utility Member revenue due to disruptions of operations from our Utility Members' commercial customers in the business of mineral extraction, natural gas, $CO_2$, oil production, or transportation of these. The extent to which the COVID-19 pandemic 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, including the adoption rate of the COVID-19 vaccines, the impact of the delta variant, the scope and the timing to further contain the virus or treat its impact, and to what extent normal economic and operating conditions resume, among others.

**Critical Accounting Policies**

The preparation of our financial statements in conformity with GAAP requires that our management make estimates and assumptions that affect the amounts reported in our consolidated financial statements. We base these estimates and assumptions on information available as of the date of the financial statements and they are not necessarily indicative of the results to be expected for the year. As of September 30, 2021, 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, 2020.

**Factors Affecting Results**

***Master Indenture***

As of September 30, 2021, 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. 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. On November 9, 2021, we transitioned to U.S. Bank National Association becoming the successor trustee under our Master Indenture.

***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 1.190 for the twelve months ended December 31, 2021 and a ECR goal of 23.5 percent as of December 31, 2021.

***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 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. The tariff rates were referred to an administrative law judge to encourage settlement of material issues and to hold a hearing if settlement is not reached. 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 current rates) thereafter 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 electric power sales to our Utility Members and non-member purchasers. Revenues from 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 2020 and 2021, 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.

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 electric power 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.

## Three months ended September 30, 2021 compared to three months ended September 30, 2020

### *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 two of our Non-Utility Members. The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the three months ended September 30, 2021 and 2020 (dollars in thousands):

| | Three Months Ended September 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2021 | 2020 | Amount | Percent |
| Operating revenues | | | | |
| Utility Member electric sales | $ 350,344 | $ 346,769 | $ 3,575 | 1.0 % |
| Non-member electric sales | 44,451 | 38,606 | 5,845 | 15.1 % |
| Other | 21,068 | 16,226 | 4,842 | 29.8 % |
| Total operating revenues | $ 415,863 | $ 401,601 | $ 14,262 | 3.6 % |
| | | | | |
| Energy sales (in MWh): | | | | |
| Utility Member electric sales | 4,645,489 | 4,512,087 | 133,402 | 3.0 % |
| Non-member electric sales | 560,066 | 533,360 | 26,706 | 5.0 % |
| | 5,205,555 | 5,045,447 | 160,108 | 3.2 % |

- Non-member electric sales increased primarily due to rate stabilization measures. In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $8.6 million of previously deferred revenue during the three months ended September 30, 2021 compared to none during the same period in 2020. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021. We expect to recognize additional previously deferred revenue during the remainder of 2021 in order to meet our financial goals.
- Other operating revenue consists primarily of wheeling and transmission revenues, and coal sales to third parties. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is from our membership in Southwest Power Pool. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine and other locations to third parties. Other operating revenue increased primarily due to higher wheeling revenue and revenue related to the sale of coal.

***Operating Expenses***

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

The following is a summary of the components of our operating expenses for the three months ended September 30, 2021 and 2020 (dollars in thousands):

| | Three Months Ended September 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2021 | 2020 | Amount | Percent |
| Operating expenses | | | | |
| Purchased power | $ 112,540 | $ 103,136 | $ 9,404 | 9.1 % |
| Fuel | 76,332 | 65,061 | 11,271 | 17.3 % |
| Production | 41,543 | 39,698 | 1,845 | 4.6 % |
| Transmission | 50,152 | 43,989 | 6,163 | 14.0 % |
| General and administrative | 15,916 | 17,081 | (1,165) | (6.8)% |
| Depreciation, amortization and depletion | 44,990 | 45,775 | (785) | (1.7)% |
| Coal mining | 1,492 | 4,200 | (2,708) | (64.5)% |
| Other | 1,562 | 2,691 | (1,129) | (42.0)% |
| Total operating expenses | $ 344,527 | $ 321,631 | $ 22,896 | 7.1 % |

- Purchased power expense increased primarily due to increased demand from our Utility Members and decreased generation from certain of our generating resources because of maintenance activities. Generation decreased (in

MWhs) 2.9 percent during the three months ended September 30, 2021 compared to the same period in 2020. Purchased power increased (in MWhs) 9.8 percent for the three months ended September 30, 2021 compared to the same period in 2020.

- Fuel expense increased primarily due to increased natural gas prices. Generation decreased (in MWhs) 14.3 percent at our combined-cycle and simple-cycle combustion generating stations during the three months ended September 30, 2021 compared to the same period in 2020. Natural gas costs at these generating stations increased $7.7 million, or 70.7 percent, during the same period.
- Transmission expense increased primarily due to a $3.5 million write-off related to a transmission project in Wyoming during the three months ended September 30, 2021.

**Nine months ended September 30, 2021 compared to nine months ended September 30, 2020**

***Operating Revenues***

The following is a comparison of our operating revenues and energy sales in MWh by type of purchaser for the nine months ended September 30, 2021 and 2020 (dollars in thousands):

| | Nine Months Ended September 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2021 | 2020 | Amount | Percent |
| Operating revenues | | | | |
| Utility Member electric sales | $ 897,587 | $ 926,529 | $ (28,942) | (3.1)% |
| Non-member electric sales | 118,770 | 71,044 | 47,726 | 67.2 % |
| Other | 51,780 | 37,150 | 14,630 | 39.4 % |
| Total operating revenues | $ 1,068,137 | $ 1,034,723 | $ 33,414 | 3.2 % |
| Energy sales (in MWh): | | | | |
| Utility Member electric sales | 12,014,631 | 12,246,955 | (232,324) | (1.9)% |
| Non-member electric sales | 1,179,076 | 1,177,370 | 1,706 | 0.1 % |
| | 13,193,707 | 13,424,325 | (230,618) | (1.7)% |

- Utility Member electric sales decreased, in terms of MWhs sold, primarily due to the withdrawal of DMEA in June 2020 and continued economic impacts of COVID-19 during the year, in particular, from our Utility Members' commercial customers. DMEA represented 3.4 percent of Utility Member revenue during the six months ended June 30, 2020. The decrease in Utility Member electric sales revenue caused by lower sales volume was slightly compounded by a 1.3 percent lower average price during the nine months ended September 30, 2021 when compared to the same period in 2020. The decrease in average price was primarily due to a two percent settlement rate reduction effective as of March 1, 2021. See Note 17 to the Unaudited Consolidated Financial Statements in Item 1 for further information.
- Non-member electric sales increased primarily due to rate stabilization measures. In accordance with our Board Policy for Financial Goals and Capital Credits, we recognized $49.4 million of previously deferred revenue during the nine months ended September 30, 2021 compared to none during the same period in 2020.
- Other operating revenues increased primarily due to increased wheeling and transmission for others as well as revenue related to the sale of coal.

***Operating Expenses***

The following is a summary of the components of our operating expenses for the nine months ended September 30, 2021 and 2020 (dollars in thousands):

| | Nine Months Ended September 30, | | Period-to-period Change | |
|---|---|---|---|---|
| | 2021 | 2020 | Amount | Percent |
| Operating expenses | | | | |
| Purchased power | $ 286,109 | $ 260,804 | $ 25,305 | 9.7 % |
| Fuel | 182,749 | 165,679 | 17,070 | 10.3 % |
| Production | 135,285 | 122,595 | 12,690 | 10.4 % |
| Transmission | 136,771 | 127,175 | 9,596 | 7.5 % |
| General and administrative | 42,400 | 49,337 | (6,937) | (14.1)% |
| Depreciation, amortization and depletion | 144,228 | 137,110 | 7,118 | 5.2 % |
| Coal mining | 3,999 | 8,021 | (4,022) | (50.1)% |
| Other | 5,395 | 13,429 | (8,034) | (59.8)% |
| Total operating expenses | $ 936,936 | $ 884,150 | $ 52,786 | 6.0 % |

- Purchased power expense increased primarily due to decreased generation from certain of our generating resources because of scheduled maintenance as well as favorable market conditions for purchasing power during the nine months ended September 30, 2021 compared to the same period in 2020. Generation decreased 9.8 percent during the nine months ended September 30, 2021 compared to the same period in 2020. Purchased power increased (in MWhs) 7.2 percent for the nine months ended September 30, 2021 compared to the same period in 2020. The average price was 3.1 percent higher during the nine months ended September 30, 2021 compared to the same period in 2020.
- Fuel expense increased primarily due to increased natural gas prices. Generation decreased 10.2 percent at our combined-cycle and simple-cycle combustion generating stations during the nine months ended September 30, 2021 compared to the same period in 2020. Natural gas costs at these generating stations increased $12.4 million, or 50.5 percent, during the same period.
- Production expense increased primarily due to the performance of scheduled maintenance postponed during the prior year as a result of COVID-19. Scheduled maintenance was performed at several generating facilities during the nine months ended September 30, 2021, resulting in $19.4 million in increased maintenance costs compared to the same period in 2020. Maintenance expenses were slightly offset by a decrease of $6.7 million in general production expenses during the nine months ended September 30, 2021 compared to the same period in 2021.
- Transmission expense increased primarily due to increased transmission and wheeling from others and a $3.5 million write-off related to a transmission project in Wyoming during the nine months ended September 30, 2021 compared to the same period in 2020.
- General and administrative expense decreased primarily due to a decrease in outside professional services and an overall decrease in general and administrative salaries.
- Depreciation, amortization and depletion expense increased primarily due to revisions to asset retirement obligations related to the South Taylor pit at the Colowyo Mine during the prior year, which began to depreciate during January 2021.
- Other expense decreased primarily due to nonrecurrent expenses recorded during the nine months ended September 30, 2020 related to providing water resources from our Escalante Generating Station, a write-off of materials and supplies, and a loss on disposition of utility property.

**Financial condition as of September 30, 2021 compared to December 31, 2020**

The principal changes in our financial condition from December 31, 2020 to September 30, 2021 were due to increases and decreases in the following:

***Assets***

- Other plant decreased $51.8 million, or 10.9 percent, to $415.8 million as of September 30, 2021 compared to $466.8 million as of December 31, 2020. The decrease was primarily due to a reduction in the asset retirement obligation of $49.1 million in 2021 for the Colowyo Coal South Taylor pit and non-utility asset retirements of $9.7 million.

***Liabilities***

- Long-term debt decreased $89.6 million, or 2.8 percent, to $3.111 billion as of September 30, 2021 compared to $3.200 billion as of December 31, 2020 and current maturities of long-term debt increased $3.6 million, or 4.1 percent, to $91.2 million as of September 30, 2021 compared to $87.6 million as of December 31, 2020. The net decrease of $86.0 million was primarily due to debt payments of $87.1 million (principally $41.0 million for the Springerville certificates, $22.0 million to pay off the remaining balance of the First Mortgage Obligations, Series 2009C, and $12.4 million of CoBank debt). During 2021, we repurchased and cancelled $4.2 million of our First Mortgage Bonds, Series 2014E-1 which resulted in a loss on extinguishment of debt of $0.4 million.
- Accrued interest increased $17.4 million, or 63.2 percent, to $44.9 million as of September 30, 2021 compared to $27.5 million as of December 31, 2020. The increase was due to accruals for interest due in future periods of $106.5 million partially offset by interest payments of $89.1 million.
- Regulatory liabilities decreased $49.8 million, or 22.1 percent, to $175.2 million as of September 30, 2021 compared to $225.0 million as of December 31, 2020. The decrease was primarily due to the recognition of $49.4 million of previously deferred non-member electric sales revenues. In order to better align with our financial goals, we have begun to recognize deferred revenue on a quarterly basis when it is reasonably estimable that recognition is required to meet our financial goals during 2021.
- Asset retirement and environmental reclamation obligations decreased $46.3 million, or 36.5 percent, to $80.7 million as of September 30, 2021 compared to $127.0 million as of December 31, 2020. The decrease was primarily due to a reduction in the Colowyo Mine reclamation liability of $50.0 million in the second quarter of 2021. This reduction was primarily related to a change in the mine plan of South Taylor pit at the Colowyo Mine. After obtaining regulatory approval, the South Taylor pit life was extended through 2027 to mine the highwall, which resulted in a lower estimated obligation at the end of the mining period.

**Liquidity and Capital Resources**

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of short-term and long-term borrowings. As of September 30, 2021, we had $97.6 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2021 is as follows (dollars in thousands):

| | Authorized Amount | | Available September 30, 2021 |
|---|---|---|---|
| Revolving Credit Agreement | $ 650,000 | (1) | $ 650,000 |

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

We have a secured Revolving Credit Agreement with aggregate commitments of $650 million. The Revolving Credit Agreement includes 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 $500 million of the commercial paper back-up sublimit remained available as of September 30, 2021.

The Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. Funds advanced under the Revolving Credit Agreement are either LIBOR rate loans or base rate loans, at our option. LIBOR rate loans bear interest at the adjusted LIBOR rate for the term of the advance plus a margin (currently 1.125 percent) based on our credit ratings. Base rate loans bear interest at the alternate base rate plus a margin (currently 0.125 percent) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00 percent, (b) the prime rate, and (c) the one-month LIBOR rate plus 1.00 percent. Upon discontinuation of the LIBOR rate, the Revolving Credit Agreement provides for CFC and us to endeavor to establish an alternative rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States. Upon discontinuation of the LIBOR rate and if no alternative rate has been established by CFC and us, all funds advances will be at base rate loans. We had no outstanding borrowings as of September 30, 2021.

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

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our Revolving Credit Agreement, which was $500 million at September 30, 2021, thereby providing 100 percent dedicated support for any commercial paper outstanding. As of September 30, 2021, we had no commercial paper outstanding and $500 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.

**Nine months ended September 30, 2021 compared to nine months ended September 30, 2020**

*Operating activities*. Net cash provided by operating activities was $170.7 million for the nine months ended September 30, 2021 compared to $305.9 million for the same period in 2020, a decrease in net cash provided by operating activities of $135.2 million. Substantially all of the decrease was due to proceeds related to the DMEA withdrawal in 2020 compared to no proceeds in 2021 and lower net margins in 2021 compared to 2020.

*Investing activities*. Net cash used in investing activities was $99.1 million for the nine months ended September 30, 2021 compared to $79.3 million for the same period in 2020, an increase in net cash used in investing activities of $19.8 million. The increase was primarily due to proceeds from the sale of electric plant related to the DMEA withdrawal in 2020 compared to no proceeds from the sale of electric plant in 2021. Partially offsetting this increase was a reduction in generation and transmission improvements and system upgrades for the nine months ended September 30, 2021 compared to the same period in 2020.

*Financing activities*. Net cash used in financing activities was $101.4 million for the nine months ended September 30, 2021 compared to $170.3 million for the same period in 2020, a decrease of $68.9 million. The decrease was primarily due to lower proceeds from issuance of long-term debt in 2021 compared to 2020 (during 2020, we borrowed $125 million from the First Mortgage Obligations, Series 2020A, $100 million from the First Mortgage Obligations, Series 2020B, and $200 million from our Revolving Credit Agreement). These decreases were partially offset by lower principal payments of long-term debt in 2021 compared to 2020.

**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 2021 through 2025, we forecast that we may invest approximately $799 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 2020 Electric Resource Plan, 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.

**Contractual Commitments**

*Indebtedness*. As of September 30, 2021, we had $3.2 billion in outstanding obligations, including approximately $2.9 billion of debt outstanding secured on a parity basis under our Master Indenture, no outstanding short-term borrowings, one unsecured loan agreement totaling $13.9 million and the Springerville certificates totaling $292.9 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease). Our debt secured by the lien of our Master Indenture includes notes payable to CFC and CoBank (with the exception of one unsecured note), the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, First Mortgage Bonds, Series 2016A, First Mortgage Obligations, Series 2017A, pollution control revenue bonds, and amounts outstanding, if any, under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture.

*Construction Obligations*. We have commitments to complete certain construction projects associated with improving the reliability of the generating facilities and the transmission system.

*Coal Purchase Obligations*. We have commitments to purchase coal for our generating facilities under long-term contracts that expire between 2024 and 2041. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. Our coal purchase obligations exclude any purchases we have with our subsidiaries.

**Environmental Regulations**

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex and change frequently. For a discussion regarding potential effects on our business from environmental regulations, see also “Item 1 – BUSINESS – ENVIRONMENTAL REGULATION” and “Item 1A – RISK FACTORS” in our annual report on Form 10-K for the year ended December 31, 2020.

**Electric Resource Plan**

On June 8, 2021, the COPUC issued an interim decision deeming our 2020 Electric Resource Plan application complete and referring the case to an administrative law judge. On June 21, 2021, the administrative law judge issued an interim decision setting the procedural schedule for our 2020 Electric Resource Plan proceeding, including a remote hearing scheduled January 31 through February 4, 2022. The procedural schedule accommodated the modeling of five additional Electric Resource Plan scenarios requested by parties to the proceeding. The results of the additional modeling, along with our Revised Preferred Plan, were filed alongside our supplemental direct testimony on September 28, 2021. Our Revised Preferred Plan includes 2,050 MWs of additional renewable generation and more than 200 MWs of energy storage occurring during the resource acquisition period of 2021 to 2030. For further information regarding our 2020 Electric Resource Plan, see “Item 1 – BUSINESS — POWER SUPPLY RESOURCES – Resource Planning” in our annual report on Form 10-K for the year ended December 31, 2020.

**Rating Triggers**

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “BBB+ (stable 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 Agreement includes a pricing grid related to the LIBOR spread, commitment fee and letter of credit fees due under the facility. We also have a term loan agreement that includes a pricing grid related to the LIBOR spread. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would 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, coal purchase contracts, and financial risk management contracts. Some of the contracts are directly tied to our credit rating generally being maintained at or above investment grade 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, 2020.

## 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 1A. Risk Factors

***The U.S. President's COVID-19 action plan concerning mandatory COVID-19 vaccination of employees could have a material adverse impact on our business and results of operations.***

On September 9, 2021, the Biden Administration announced a plan to reduce the number of unvaccinated Americans through an OSHA Emergency Temporary Standard and Executive Order 14042. The OSHA Emergency Temporary Standard provides, generally, that all employers with 100 or more employees require that all employees be vaccinated or undergo weekly COVID-19 testing and the final rule largely mirror these requirements. Executive Order 14042 provides, generally, that federal agencies ensure that covered contracts and contract-like instruments include a clause that the federal contractor and any subcontractor be fully vaccinated against COVID-19. The Executive Order applies to a broad category of contracts.

We continue to evaluate if Executive Order 14042 is applicable to us and await guidance from the applicable federal agencies. Under the OSHA Emergency Temporary Standard final rule, we will be required to mandate COVID-19 vaccination of our employees or our unvaccinated employees will require weekly testing.  If Executive Order 14042 is applicable to us, the option of weekly testing would not be available and mandatory vaccination would be required, subject to approved medical or religious accommodations. Both the OSHA Emergency Temporary Standard and Executive Order 14042 may result in employee attrition, which could be material as a substantial number of our employees are believed to be unvaccinated. If we were to lose employees, it could have an adverse effect on our ability to operate and maintain our transmission system, our generating facilities, and our coal mine and lead to service outages, business interruptions, and our ability to delivery power to our Utility Members, which could have an adverse effect on future revenues and costs, which could be material. Accordingly, either of these regulations when implemented could have a material adverse effect on our business and results of operations.

## 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 |
|---|---|
| 3.2 | Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc., dated August 5, 2021 |
| 31.1 | Rule 13a-14(a)/15d-14(a) Certification, by Duane Highley (Principal Executive Officer). |
| 31.2 | Rule 13a-14(a)/15d-14(a) Certification, by Patrick L. Bridges (Principal Financial Officer). |
| 32.1 | Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Duane Highley (Principal Executive Officer). |
| 32.2 | Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Patrick L. Bridges (Principal Financial Officer). |
| 95 | Mine Safety Disclosure Exhibit. |
| 101 | XBRL Interactive Data File. |

## SIGNATURES

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

Tri-State Generation and Transmission Association, Inc.

Date: November 10, 2021

By: /s/ Duane Highley
Duane Highley
Chief Executive Officer

Date: November 10, 2021

/s/ Patrick L. Bridges
Patrick L. Bridges
Senior Vice President/Chief Financial Officer (Principal Financial Officer)