2020 LEADING THE CHARGE

TRI-STATE ANNUAL REPORT


RELIABLE
AFFORDABLE
RESPONSIBLE

Introduction

Through 2020, Tri-State led the charge into the most significant transformation in our history. While safely managing the challenges of the pandemic, we advanced our mission to reliably, affordably and responsibly serve our members' power needs within the not-for-profit cooperative business model.

Tri-State's resources performed well, with our generation and transmission resources reliably and cost-effectively operating to serve members' loads, while energy management functions ensured that we remained competitive in the power markets. Our cooperative met all financial goals, maintained stable rates and returned patronage capital to our members.

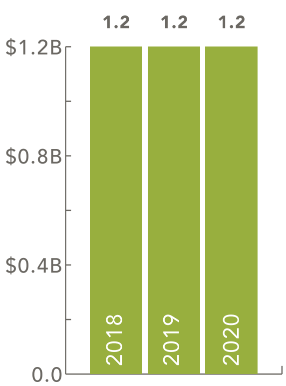

RELIABLE


AFFORDABLE

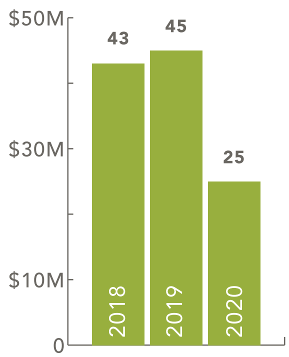

RESPONSIBLE

Quick facts & financials

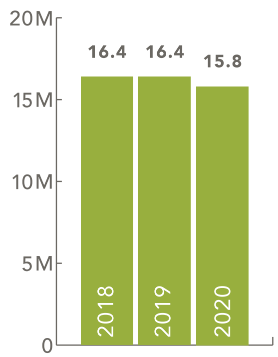
$1.4B operating revenue	**126MW** member generation from community renewables	**$25M** net margin
7.5¢/kWh average member wholesale rate	**$5.0B** total assets	**$30M** in patronage capital returned to our members



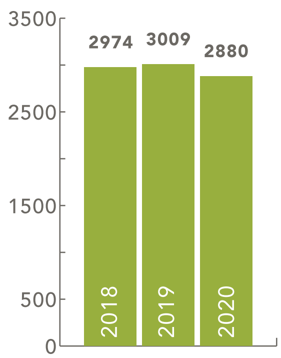
OPERATING EXPENSES



NET MARGIN

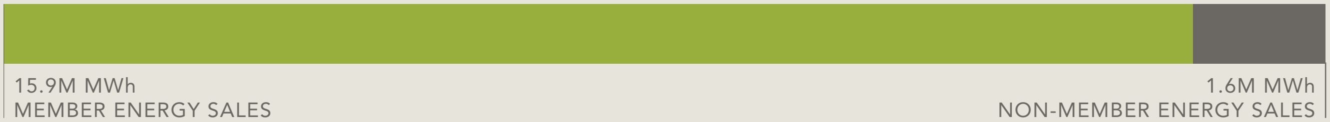


ENERGY SOLD TO MEMBERS (MWh)

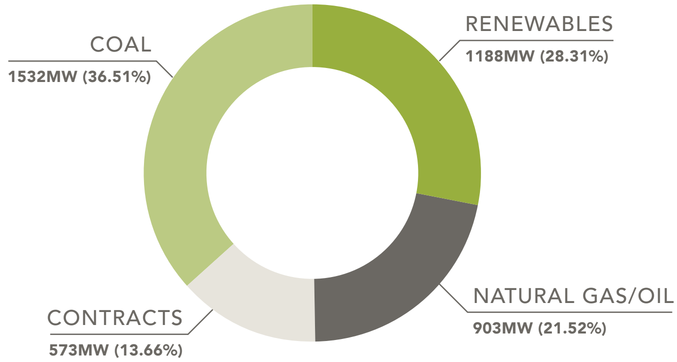


MEMBER COINCIDENT PEAK DEMAND (MW)

17.5M MWh Total Energy Sold



Sources of generation



Since 2019, we have decreased our coal capacity by almost 20% while committing to an additional 1,000 megawatts of renewable energy. With the completion of these projects, renewables will be the majority resource in our generation portfolio.

Upcoming renewable projects

200MW	Niyol Wind (2021) Logan and Yuma Counties, Colorado
104MW	Crossing Trails Wind (2021) Kit Carson and Cheyenne Counties, Colorado
140MW	Coyote Gulch Solar (2023) Montezuma County, Colorado
100MW	Spanish Peaks Solar (2023) Las Animas County, Colorado
110MW	Dolores Canyon Solar (2023) Dolores County, Colorado
145MW	Axial Basin Solar (2023) Moffat County, Colorado
200MW	Escalante Solar (2023) McKinley County, New Mexico
40MW	Spanish Peaks II Solar (2023) Las Animas County, Colorado

"As is often the cooperative way, our members thoughtfully lead forward, and they deliberately work in the best interest of all those they serve."

Tri-State's members are working together and leading the charge to ensure our power supply cooperative's transformation will serve the needs of our consumer-members in a rapidly changing environment, and for many years to come.

As the pandemic changed the way we work, our board, which represents all of our utility members, adapted to a largely remote setting to continue to deliver on its important responsibility to democratically govern Tri-State, setting and then advancing our goals.

Central to our work is how our cooperative business model has guided the implementation of our Responsible Energy Plan. Throughout the year, the board considered many issues, deliberated and developed the consensus that is guiding Tri-State through its clean energy transition.

In a process that is unique to generation and transmission cooperatives, our members worked together to establish how they will have more flexibility in their wholesale power contracts. Following our board of directors' approval of the members' recommendations, the Federal Energy Regulatory Commission accepted filings that advance contract options, while protecting those members that will maintain their current contracts.

Our member distribution systems draw strength, stability and security from membership in Tri-State, which effectively manages the growing risks of power supply, such as dynamic markets or the impact of severe weather events, and reliably provides all needed services as part of our wholesale rate.

For the fifth straight year and into 2021, member wholesale rates were unchanged, and Tri-State returned $30 million in patronage capital to our members. Over the last five years, Tri-State has returned a total of $130 million to our members.

As we implement our clean energy transition, it is our goal to do so while also lowering member rates. Accordingly, our board set a goal to reduce wholesale rates, and we have embarked on a long- term strategy to address costs.

It has been a privilege to serve as chairman of the board of directors over the past decade. Our board has made great strides in our work together, ensuring that every voice is heard and that together, we lead Tri-State to deliver the full value of the cooperative business model in the best interests of all our members.

I want to thank my fellow directors for their thoughtful engagement and recognize Tri-State's talented staff for all they do to serve our mission.

Rick Gordon, Chairman

Rick Gordon, Tri-State Chairman

MOUNTAIN VIEW ELECTRIC ASSOCIATION BOARD MEMBER SINCE 1992 AND TRI-STATE BOARD CHAIRMAN FOR 11 CONSECUTIVE YEARS

@HIGHLEYUNLIKELY

Duane Highley, Tri-State CEO

"I believe Tri-State will be a leader in the cooperative world and recognized as the most competitive power supply option for our members."

In the electric utility industry, a sound operational and financial position, driven by discipline and planning, prepares organizations to capture emerging opportunities, as well as manage through unexpected adversity.

In 2020, Tri-State leveraged these strengths and the benefits of the not-for-profit cooperative business model to launch a rapid clean energy transition and add greater flexibility for our members, while safely maintaining operations, aligning staff action with our mission and board goals, and managing risks through an unprecedented pandemic.

With the guidance of our board of directors, representing each of Tri-State's utility members, and the hard work, deep talents and preparation of our staff, Tri-State began the year with the announcement of our transformational Responsible Energy Plan.

Construction began on the first of eight solar and wind projects that will deliver more than 1,000 megawatts of clean energy to our members. As our remaining New Mexico coal-fired power plant was retired, we were hard at work to ensure our affected employees and communities received meaningful transition support.

As a cooperative family, our purpose is to serve our consumer-members in all we do. Along with our members we enhanced energy efficiency products and established new beneficial electrification programs that extend the benefits of a cleaner grid.

As we made progress on our plan, Tri-State and our board set the bar higher with new goals that will further increase Tri-State's competitive position. These goals include lowering our wholesale rates to members and achieving 70% clean energy by 2030.

With the recognition that organized markets are necessary to reliably, affordably and responsibly serve our members and meet our goals, we prepared to enter two energy imbalance markets in early 2021, while evaluating with other power suppliers the benefits of participating in a western regional transmission organization.

Our continuing advancement of this progress in the throes of the pandemic is a testament to the focus and dedication of our staff, who safely maintained operations even as the way we work necessarily changed.

The performance of our staff who operate our power plants, maintain our transmission system and manage our energy resources, along with all the other employees who allow us to serve our members, was exemplary.

Together, Tri-State, our board of directors, members and staff are leading the charge to change how our communities are powered.

Duane Highley, Chief Executive Officer

Responsible energy

“By 2024, we’re going to have 50% of the energy consumed by our members coming from clean energy sources.”

– Duane Highley, Tri-State CEO on the Responsible Energy Plan

CROSSING TRAILS WIND FARM CONSTRUCTION

EV EXPERIENCE FLEET

Responsible Energy Plan delivers results

In January 2020, Tri-State released our cooperative’s clean energy transition plan, which expands renewable generation and reduces greenhouse gas emissions, while ensuring reliable, affordable and responsible electricity for our members. With our Responsible Energy Plan (REP), Tri-State is implementing a clean energy transition, while being responsible to our employees, our members, our communities, and our environment. The REP is dynamic and will change as our members’ needs change, as new technologies become available and market conditions evolve. Over the past year, Tri-State and our members have made great strides implementing the plan.

Since 2019, we’ve worked with members, legislators and employees to support the main goals of the REP: increasing clean energy, reducing emissions, increasing member flexibility, extending the benefits of a clean grid and supporting our communities, all to create a brighter future.

Increasing clean energy

By 2024, Tri-State will bring more than 1,000 megawatts (MW) of utility-scale solar and wind projects online, more than doubling these resources on our system to 2,000 MW. By 2030, our goal is that 70% of the energy supplied to members system-wide will be clean energy, with another 1,850 MW of renewable resources identified in Tri-State electric resource plans. The first project in the REP, the Crossing Trails Wind Project, began construction in eastern Colorado in 2020, with commercial operation in 2021.

Reducing emissions

We set ambitious goals for emission reductions and eliminated carbon dioxide (CO_2) emissions from coal generation in New Mexico in 2020. By 2030 in Colorado, we are targeting a 100% reduction in CO_2 emissions from coal generation and an 80% reduction in CO_2 emissions associated with wholesale electricity sales in the state.

Adding member flexibility

Our members worked together to develop a more flexible contract structure so that they can self-supply more power than ever before. A contract committee of the membership finalized and delivered its recommendations to our board for a flexible partial requirements membership option and added flexibility for members interested in developing community solar projects.

Extending a clean grid

To leverage the benefits of a cleaner grid, Tri-State committed resources to extend the public electric vehicle (EV) charging network across members' service territories and is promoting EVs and EV solutions in rural areas. We're expanding programs to help consumers save money and energy, while cutting emissions through energy efficiency, beneficial electrification and other initiatives.

Supporting our communities

With the retirement of Nucla Station in 2019 and Escalante Station in 2020, Tri-State's efforts include retraining and transition support for employees affected by facility retirements and working with impacted communities in Colorado and New Mexico to support meaningful economic development opportunities. We are also working with local, state and federal leaders to support a just transition for coal-dependent communities.

Our priorities

100 miles

of transmission line added this year to serve member loads and ensure reliability

$130M

Patronage capital returned to the membership in the last five years

120

EV chargers installed, driving an estimated 300,000 kWh of new energy sales annually

Reliable, affordable, responsible power

This year, Tri-State advanced several priorities for our organization, including further participation in organized markets, ensuring regulatory certainty, maintaining financial strength and focusing on member needs, all of which are essential to serving our mission over the long term.

Recognizing the importance of regional power markets for reliability, cost savings and renewable energy integration, preparations were made for the successful entry into two energy imbalance markets. Along with other regional power suppliers, Tri-State also began evaluating the participation of our western grid load in a potential expansion of the Southwest Power Pool regional transmission organization.

The benefits of regulatory certainty, with consistent wholesale rate regulation for our cooperative's member systems across four states from a single rate regulator, were advanced as the Federal Energy Regulatory Commission (FERC) accepted our tariff filings, including our wholesale rates and in support of partial requirements memberships.

Tri-State's financial strength was preserved as the pandemic affected financial markets. Throughout the first and second quarter, Tri-State successfully navigated through a liquidity crisis affecting the financial markets and closed on two long-term financings at historically low rates, even as year-over-year total debt declined.

Tri-State's focus on our members extended beyond supplying power to helping sustain the communities we serve together. Tri-State supported pandemic relief efforts in four states, as well as relief for communities affected by a devastating wildfire season. During the western drought, Tri-State released water to assist with critical flows in the Yampa River in Colorado.

TRI-STATE DONATED $60K IN MATCHED FUNDS TO THE YAMPA RIVER FUND FOR COMMUNITIES, AGRICULTURE AND ENVIRONMENT

Safety is vital to every aspect of our cooperative. This year, even with the additional pressures of the pandemic, our generation and transmission teams were recognized statewide and nationally for their efforts.

NATIONAL SAFETY COUNCIL

- SUPERIOR SAFETY PERFORMANCE
- SAFETY LEADERSHIP
- PERFECT RECORD AWARDS

COLORADO MINING ASSOCIATION

- EXCELLENCE IN SAFETY FOR A LARGE SURFACE COAL MINE

MULLEN FIRE, WY

Some members and their communities faced multiple crises in 2020, and Tri-State was proud to support recovery efforts. Some of our contributions included:

- $200,000 TO PANDEMIC RELIEF EFFORTS ACROSS COLORADO, NEBRASKA, NEW MEXICO, AND WYOMING
- $30,000 TO SUPPORT MULLEN FIRE RELIEF EFFORTS
- $50,000 IN MATCHED DONATIONS FOR COLORADO WILDFIRE RELIEF EFFORTS

We've always valued responsibility. Our energy efficiency program for our members has been in place since 1985, and in 2020 our programs has a meaningful impact:

- $3M IN ENERGY EFFICIENCY PRODUCT INCENTIVES
- 8,704 ENERGY EFFICIENCY REBATES PROCESSED
- SUPPORTING PUBLIC ELECTRIC VEHICLE INFRASTRUCTURE WITH $45,000 PER MEMBER ALLOCATED TO INSTALL EV CHARGERS

ESCALANTE STATION, NM

In 2020, Tri-State commenced demolition of Nucla Station in western Colorado, retired Escalante Station in New Mexico, and is working with and local, state and federal leaders to support the affected communities' transition.

DOLORES CANYON, CO

This year, Tri-State completed a seven-year transmission upgrade that required teams to connect transmission line across Dolores Canyon near Empire, Colo. This crossing is one of the largest in the world.

"AG LAB" FOOD PRODUCTION POD

In 2020, Tri-State and the Electric Power Research Insititute (EPRI) partnered to bring an indoor food production pod to Craig, Colo., to help students learn about energy, water and light use while growing produce entirely indoors in a specially-designed shipping container.

Serving member needs

Our priorities align with our members'

To ensure our members' needs are always met, Tri-State focuses on strategic priorities of reliability, affordability, flexibility and responsibility.

First and foremost is our members' need for reliable power. With a goal to maintain 99.995% reliability for members, Tri- State ensures we have adequate resources to serve load, and we maintain our generation fleet and vast transmission network to meet our members' needs every day of the year, even under challenging conditions.

In 2020, several generation and transmission projects were completed to support reliable operations, including a transmission project with one of the longest canyon crossings in the United States. Notably, Tri-State completed construction work on 18 member delivery points, 13 of which were new delivery points.

We also successfully implemented compliance with seven new or modified North American Electric Reliability Corporation (NERC) standards and continued to mature our internal NERC compliance program.

With our members' need for affordable and competitive wholesale power, Tri-State is focused on managing costs, with a goal to reduce our wholesale rates. To bolster revenues, Tri-State also pursued new energy and reserve sales, and increased non-member energy sales above budget in 2020, which supports affordable member wholesale rates.

Through 2021 and for the fifth straight year, Tri-State maintained stable rates. In 2020, $30 million in patronage capital was returned to our members, and over the past five years, Tri-State has returned $130 million to our members.

For many years, Tri-State's contracts have provided opportunities for members to locally generate up to 5% of their power requirements. Some members have the need for additional flexibility, and Tri-State has set a goal to support those members.

In 2020, our board approved member-developed approaches to further increase the self-supply of power, including a new partial requirements membership option that totals approximately 10% of Tri-State total load, and a new community solar program that increases opportunities for consumer-members to participate in renewable energy projects.

Our membership also developed and our board approved the methodologies to calculate the cost of changing to a partial requirements contract, and for the early termination of a member's wholesale power contract. These methodologies were filed with FERC, and provide flexibility to those members that desire it, while protecting the financial interests of those members that wish to continue under their current contracts.

With the adoption of the Responsible Energy Plan, our members continue to support the wise use of electricity, among other clean energy transition initiatives. Tri-State provided $3 million in energy efficiency incentives through nearly 9,000 rebates.

To support beneficial electrification and further emissions reductions driven by consumer action, we initiated a heat pump quality installation program with our members to support building electrification. We are working with stakeholders in our regions to increase the market availability of heat pumps and qualified installers. With the support of our incentive programs, our members have installed more than 120 EV chargers, and through our promotion of EVs, more than 1,200 drivers from 16 members have experienced our EV test fleet.

As we lead the charge, Tri-State's management and staff remain focused on our mission. Our safety record remained better than the national average, with 10 National Safety Council awards, and we maintained compliance with safety, reliability and environmental requirements.

We are taking significant steps to align our staff activities with our mission, and building an engaged, diverse and inclusive workforce that prepares our future leaders, embraces the cooperative culture and empowers all employees to serve our vital mission.

Our members

COLORADO

EM Empire Electric Association, Inc., Cortez
GC Gunnison County Electric Association, Inc., Gunnison
HL Highline Electric Association, Holyoke
KC K.C. Electric Association, Inc., Hugo
LP La Plata Electric Association, Inc., Durango
MC Morgan County Rural Electric Association, Fort Morgan
MP Mountain Parks Electric, Inc., Granby
MV Mountain View Electric Association, Inc., Limon
PV Poudre Valley Rural Electric Association, Inc., Fort Collins
SI San Isabel Electric Association, Inc., Pueblo West
SV San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
SM San Miguel Power Association, Inc., Nucla
SC Sangre de Cristo Electric Association, Inc., Buena Vista
SE Southeast Colorado Power Association, La Junta
UN United Power, Inc., Brighton
WR White River Electric Association, Inc., Meeker
YW Y-W Electric Association, Inc., Akron

NEBRASKA

CR Chimney Rock Public Power District, Bayard
MW Midwest Electric Cooperative Corporation, Grant
NW Northwest Rural Public Power District, Hay Springs
PH Panhandle Rural Electric Membership Association, Alliance
RS Roosevelt Public Power District, Scottsbluff
WB Wheat Belt Public Power District, Sidney

NEW MEXICO

CN Central New Mexico Electric Cooperative, Inc., Mountainair
CO Columbus Electric Cooperative, Inc., Deming
CD Continental Divide Electric Cooperative, Inc., Grants
JM Jemez Mountains Electric Cooperative, Inc., Española
MO Mora-San Miguel Electric Cooperative, Inc., Mora
NR Northern Rio Arriba Electric Cooperative, Inc., Chama
OC Otero County Electric Cooperative, Inc., Cloudcroft
SR Sierra Electric Cooperative, Inc., Elephant Butte
SO Socorro Electric Cooperative, Inc., Socorro
SW Southwestern Electric Cooperative, Inc., Clayton
SP Springer Electric Cooperative, Inc., Springer

WYOMING

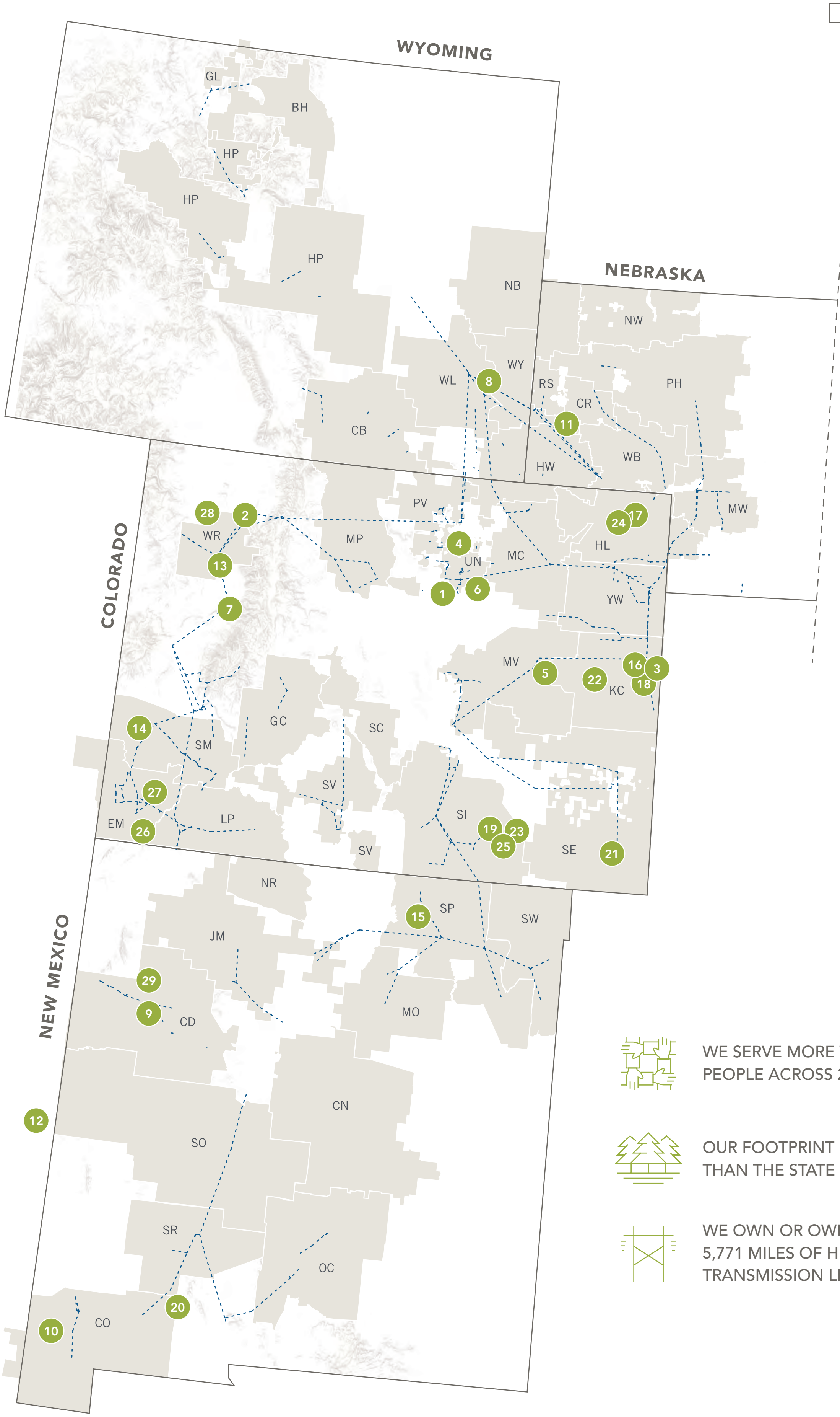
BH Big Horn Rural Electric Company, Basin
CB Carbon Power & Light, Inc., Saratoga
GL Garland Light & Power Company, Powell
HP High Plains Power, Inc., Riverton
HW High West Energy, Inc., Pine Bluffs
NB Niobrara Electric Association, Inc., Lusk
WL Wheatland Rural Electric Association, Wheatland
WY Wyrulec Company, Torrington

NON-UTILITY MEMBERS

Ellgen Ranch Company
MIECO, Inc.
Olson's Greenhouses of Colorado, LLC

Our resources

1. Headquarters and Operations Center Westminster, CO
2. Craig Station Craig, CO
3. Burlington Station Burlington, CO
4. J.M. Shafer Generating Station Fort Lupton, CO
5. Limon Generating Station Limon, CO
6. Frank R. Knutson Generating Station Brighton, CO
7. Rifle Generating Station Rifle, CO
8. Laramie River Station Wheatland, WY
9. Escalante Generating Station (Retired in 2020) Prewitt, NM
10. Pyramid Generating Station Lordsburg, NM
11. David A. Hamil DC Tie Stegall, NE
12. Springerville Generating Station Springerville, AZ
13. Colowyo Mine Meeker, CO
14. New Horizon Mine (in full reclamation) Nucla, CO
15. Cimarron Solar Colfax County, NM
16. Kit Carson Windpower Kit Carson County, CO
17. Colorado Highlands Wind Logan County, CO
18. Carousel Wind Kit Carson County, CO
19. San Isabel Solar Las Animas County, CO
20. Alta Luna Solar Luna County, NM
21. Twin Buttes II Wind Prowers County, CO
22. Crossing Trails Wind (2020) Kit Carson & Cheyenne Counties, CO
23. Spanish Peaks Solar (2023) Las Animas County, CO
24. Niyol Wind (2021) Logan & Washington Counties, CO
25. Spanish Peaks II Solar (2023) Las Animas County, CO
26. Coyote Gulch Solar (2023) Montezuma County, CO
27. Dolores Canyon Solar (2023) Dolores County, CO
28. Axial Basin Solar (2023) Moffat County, CO
29. Escalante Solar (2023) McKinley County, NM



WE SERVE MORE THAN 1 MILLION PEOPLE ACROSS 200,000 MI^2

OUR FOOTPRINT IS 20% LARGER THAN THE STATE OF CALIFORNIA

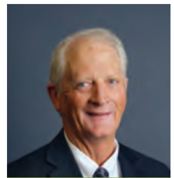
WE OWN OR OWN CAPACITY ON 5,771 MILES OF HIGH VOLTAGE TRANSMISSION LINE

AS A COOPERATIVE, WE ARE

BETTER TOGETHER

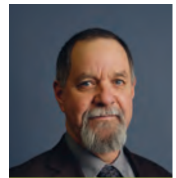
Our board of directors is comprised of representatives from our 42 distribution utility members and meets monthly to make governing decisions based on the seven cooperative principles, sound financial principles, utility industry best practices, and the needs of our members. Through the board and member committees, we are able to meet our members' diverse needs.

Our Board of Directors



CHAIRMAN

Rick Gordon
Mountain View Electric

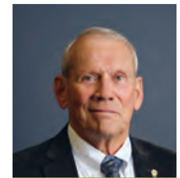


VICE CHAIRMAN

Tim Rabon
Otero County Electric

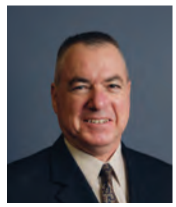
SECRETARY

Julie Kilty
Wyrulec Company

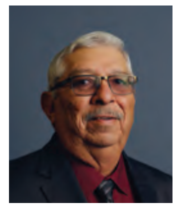


TREASURER

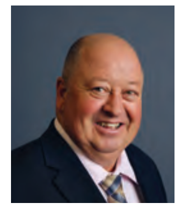
Stuart Morgan
Wheat Belt Public Power



Charles Abel II
Sangre de Cristo Electric



Leroy Anaya
Socorro Electric



Robert Baca
Mora-San Miguel Electric

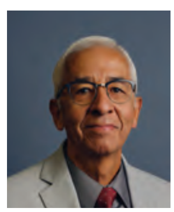
Lucas Bear
Northwest Rural Public Power

Jerry Fetterman
Empire Electric

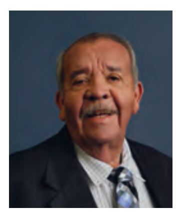
Jack Finnerty
Wheatland Rural Electric

Joel Gilbert
Southwestern Electric

Randy Graff
Morgan County Rural Electric



Steve Rendon
Northern Rio Arriba Electric

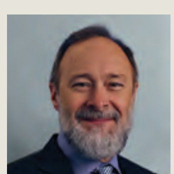


Claudio Romero
Continental Divide Electric

Peggy Ruble
Garland Light & Power

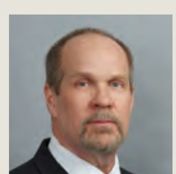
Roger Schenk
Y-W Electric

Our Executive Team



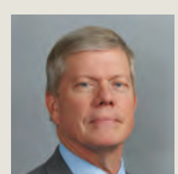
DUANE HIGHLEY

Chief Executive Officer



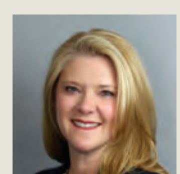
JOEL BLADOW

Senior Vice President Transmission



PAT BRIDGES

Senior Vice President and Chief Financial Officer



JENNIFER GOSS

Senior Vice President Member Relations and Chief Technology Officer


ASST. SECRETARY

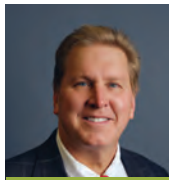
Matt Brown
High Plains Power


ASST. SECRETARY

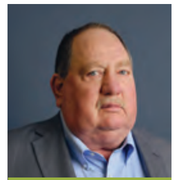
Scott Wolfe
San Luis Valley Rural Electric


EXEC. COMMITTEE

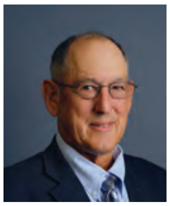
Wayne Connell
Central New Mexico Electric


EXEC. COMMITTEE

Don Keairns
San Isabel Electric


EXEC. COMMITTEE

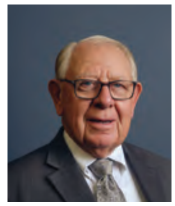
Shawn Turner
Midwest Electric Cooperative


Robert Bledsoe
K.C. Electric


Lawrence Brase
Southeast Colorado Power


Leo Brekel
Highline Electric


Willie Bridges
Big Horn Rural Electric

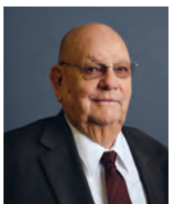

Jerry Burnett
High West Energy


Lucas Cordova Jr.
Jemez Mountains Electric


Mark Daily
Gunnison County Electric

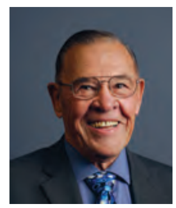

Ron Hilkey
White River Electric


Ralph Hilyard
Roosevelt Public Power


Hal Keeler
Columbus Electric


Kohler McInnis
La Plata Electric


Brian McCormick
United Power


Thaine Michie
Poudre Valley Rural Electric


Stan Propp
Chimney Rock Public Power


Gary Shaw
Springer Electric

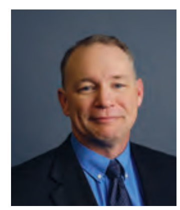

Jack Sibold
San Miguel Power


Darryl Sullivan
Sierra Electric


Clay Thompson
Carbon Power & Light

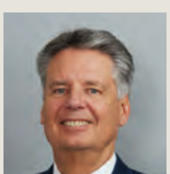

Carl Trick II
Mountain Parks Electric


William Wilson
Niobrara Electric

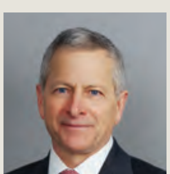

Phil Zochol
Panhandle Rural Electric


BARRY INGOLD

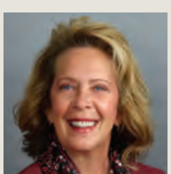
Senior Vice President
Generation


KEN REIF

Senior Vice President
General Counsel


BRAD NEBERGALL

Senior Vice President
Energy Management


BARBARA WALZ

Senior Vice President
Policy and Compliance, and Chief Compliance Officer

7 Cooperative Principles

1 OPEN & VOLUNTARY MEMBERSHIP

2 DEMOCRATIC MEMBER CONTROL

3 MEMBERS' ECONOMIC PARTICIPATION

4 AUTONOMY & INDEPENDENCE

5 EDUCATION, TRAINING & INFORMATION

6 COOPERATION AMONG COOPERATIVES

7 CONCERN FOR COMMUNITY

Everything we do is rooted in our cooperative principles. These principles have served as a guide for our cooperative family for more than 60 years. We do this because it still rings true today that we are better when we work together.

BUILT BY AND FOR OUR MEMBERS, WE POWER WHAT MATTERS TO YOU. THAT'S THE VALUE OF OUR COOPERATIVE FAMILY.

Report of Ernst & Young LLP, Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the "Association") as of December 31, 2020 and 2019, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Association at December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Association is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Association's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

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

	Asset Retirement Obligations – Coal Mines
Description of the Matter	As discussed in Note 2 and 4 to the consolidated financial statements, the Association's obligations for the final reclamation costs and post-reclamation monitoring of the Association's coal mines are recognized at estimated fair value at the time the obligations are incurred and capitalized as part of the related long-lived asset. As changes in estimates occur, such as mine plans, estimated costs and timing

of reclamation activities, the Association makes revisions to the asset retirement obligation at the appropriate discount rate.

Auditing the Association’s asset retirement obligations for coal mines required us to make subjective auditor judgements because the estimates underlying the determination of the obligations were based on significant assumptions utilized by management and their engineering staff. In particular, the fair value of the asset retirement obligation is determined by using a present value technique which is based on, among other things, estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes.

How We Addressed the Matter in Our Audit

To audit the asset retirement obligation for coal mines, our procedures included evaluating the appropriateness of the Association’s methodology and testing significant assumptions, as discussed above, and the underlying data used by the Association in its estimate. To assess the estimates of disturbed areas, reclamation costs, timing of reclamation activities, and probability of outcomes, we evaluated significant changes from the prior year estimate and verified consistency between the timing of activities to the projected mine life or reclamation plan. We also considered the appropriateness of the estimated reclamation costs for coal mines, compared anticipated labor and equipment costs to recent operating data and third-party evidence including common industry references, and recalculated management’s estimate. We involved our specialists in our assessment of the Association’s asset retirement obligations including reviewing the Association’s methodology, interviewing members of the Association’s engineering staff, evaluating the reasonableness of the cost estimates and assumptions, and assessing completeness of the estimate with respect to regulatory requirements.

Ernst & Young LLP

We have served as the Association’s auditor since 1977.

Denver, Colorado
March 5, 2021

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

As of December 31,	2020	2019
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 6,254,652	$ 6,090,392
Construction work in progress	89,447	164,924
Total electric plant	6,344,099	6,255,316
Less allowances for depreciation and amortization	(2,991,393)	(2,641,470)
Net electric plant	3,352,706	3,613,846
Other plant	456,924	409,051
Less allowances for depreciation, amortization and depletion	(133,012)	(113,607)
Net other plant	323,912	295,444
Total property, plant and equipment	3,676,618	3,909,290
Other assets and investments		
Investments in other associations	162,975	161,945
Investments in and advances to coal mines	2,799	19,681
Restricted cash and investments	4,682	30,516
Other noncurrent assets	14,889	8,654
Total other assets and investments	185,345	220,796
Current assets		
Cash and cash equivalents	127,187	83,070
Restricted cash and investments	205	182
Deposits and advances	32,012	28,434
Accounts receivable—Members	96,637	105,371
Other accounts receivable	20,570	28,039
Electric plant held for sale	4,877	—
Coal inventory	55,762	50,191
Materials and supplies	82,119	93,632
Total current assets	419,369	388,919
Deferred charges		
Regulatory assets	710,268	497,279
Prepayment—NRECA Retirement Security Plan	21,490	26,862
Other	33,646	42,672
Total deferred charges	765,404	566,813
Total assets	**$ 5,046,736**	**$ 5,085,818**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 978,519	$ 1,031,063
Accumulated other comprehensive loss	(5,714)	(1,518)
Noncontrolling interest	114,851	111,717
Total equity	1,087,656	1,141,262
Long-term debt	3,200,181	3,063,351
Total capitalization	4,287,837	4,204,613
Current liabilities		
Member advances	16,592	18,025
Accounts payable	98,654	99,033
Short-term borrowings	—	252,323
Accrued expenses	40,736	43,761
Current asset retirement obligations	11,044	2,460
Accrued interest	27,520	29,716
Accrued property taxes	32,794	29,129
Current maturities of long-term debt	87,587	81,555
Total current liabilities	314,927	556,002
Deferred credits and other liabilities		
Regulatory liabilities	224,953	122,169
Deferred income tax liability	19,591	58,937
Asset retirement and environmental reclamation obligations	127,045	76,454
Other	54,600	56,399
Total deferred credits and other liabilities	426,189	313,959
Accumulated postretirement benefit and postemployment obligations	17,783	11,244
Total equity and liabilities	**$ 5,046,736**	**$ 5,085,818**

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

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

For the years ended December 31,	2020	2019	2018
Operating revenues			
Member electric sales	$ 1,196,232	$ 1,238,672	$ 1,235,872
Non-member electric sales	102,518	95,401	34,763
Other	53,545	51,399	50,202
	1,352,295	1,385,472	1,320,837
Operating expenses			
Purchased power	335,814	328,921	343,509
Fuel	234,844	280,325	237,721
Production	171,188	209,586	212,917
Transmission	170,933	163,757	161,652
General and administrative	69,796	49,607	33,046
Depreciation, amortization and depletion	185,243	157,734	154,975
Coal mining	11,691	10,027	637
Other	15,126	19,090	14,987
	1,194,635	1,219,047	1,159,444
Operating margins	**157,660**	**166,425**	**161,393**
Other income			
Interest	4,218	6,175	5,294
Capital credits from cooperatives	11,803	9,799	27,373
Other	1,831	18,427	5,131
	17,852	34,401	37,798
Interest expense			
Interest	151,423	160,169	162,350
Interest charged during construction	(6,088)	(8,699)	(8,646)
	145,335	151,470	153,704
Income tax benefit	(534)	(307)	(534)
Net margins including noncontrolling interest	30,711	49,663	46,021
Net margin attributable to noncontrolling interest	(5,590)	(4,354)	(3,287)
Net margins attributable to the Association	**$ 25,121**	**$ 45,309**	**$ 42,734**

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

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

For the years ended December 31,	2020	2019	2018
Net margins including noncontrolling interest	$ 30,711	$ 49,663	$ 46,021
Other comprehensive income (loss):			
Unrealized gain on securities available for sale	—	—	—
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,332	(1,341)	456
Reclassification of unrealized gain on securities available for sale included in net margin	—	—	(159)
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net margin	1,845	(338)	288
Unrecognized prior service cost (credit)	(7,373)	(214)	—
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	(4,196)	(1,893)	585
Comprehensive income including noncontrolling interest	26,515	47,770	46,606
Net comprehensive income attributable to noncontrolling interest	(5,590)	(4,354)	(3,287)
Comprehensive income attributable to the Association	**$ 20,925**	**$ 43,416**	**$ 43,319**

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

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

For the years ended December 31,	2020	2019	2018
Patronage capital equity at beginning of period	$ 1,031,063	$ 1,015,754	$ 1,003,020
Net margins attributable to the Association	25,121	45,309	42,734
Retirement of patronage capital	(77,665)	(30,000)	(30,000)
Patronage capital equity at end of period	**978,519**	**1,031,063**	**1,015,754**
Accumulated other comprehensive income (loss) at beginning of period	(1,518)	375	(210)
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,332	(1,341)	456
Reclassification adjustment for unrealized gain on securities available for sale included in net margin	—	—	(159)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net margin	1,845	(338)	288
Unrecognized prior service cost	(7,373)	(214)	—
Accumulated other comprehensive income (loss) at end of period	**(5,714)**	**(1,518)**	**375**
Noncontrolling interest at beginning of period	111,717	110,169	111,295
Net comprehensive income attributable to noncontrolling interest	5,590	4,354	3,287
Equity distribution to noncontrolling interest	(2,456)	(2,806)	(4,413)
Noncontrolling interest at end of period	**114,851**	**111,717**	**110,169**
Total equity at end of period	**$ 1,087,656**	**$ 1,141,262**	**$ 1,126,298**

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

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

For the years ended December 31,	2020	2019	2018
Operating activities			
Net margins including noncontrolling interest	$ 30,711	$ 49,663	$ 46,021
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	185,243	157,734	154,975
Amortization of intangible asset	—	3,662	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,372
Amortization of debt issuance costs	2,460	2,375	2,641
Impairment loss	274,645	37,067	—
Deferred impairment loss and other closure costs	(283,047)	(37,067)	—
Deferred membership withdrawal income	110,165	—	—
Deferred revenue	—	—	51,679
Recognition of deferred revenue	(12,136)	(6,153)	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,268)	(1,276)	(18,090)
Changes in operating assets and liabilities:			
Accounts receivable	17,358	2,383	(5,922)
Coal inventory	(5,571)	5,692	(8,080)
Materials and supplies	(40)	154	(3,576)
Accounts payable and accrued expenses	(844)	1,136	(10,434)
Accrued interest	(2,196)	(2,354)	(782)
Accrued property taxes	3,665	547	1,446
Other	6,402	14,328	(6,297)
Net cash provided by operating activities	**330,919**	**233,263**	**216,277**
Investing activities			
Purchases of plant	(142,152)	(212,815)	(280,712)
Sale of electric plant	26,000	—	—
Changes in deferred charges	(4,885)	9,347	(2,233)
Proceeds from other investments	733	65	67
Net cash used in investing activities	**(120,304)**	**(203,403)**	**(282,878)**
Financing activities			
Changes in Member advances	(7,837)	(4,177)	(1,717)
Payments of long-term debt	(282,757)	(96,099)	(133,848)
Proceeds from issuance of long-term debt	425,000	34,910	150,090
Debt issuance costs	(637)	(13)	(10,697)
Increase (decrease) in short-term borrowings, net	(252,323)	48,178	59,478
Retirement of patronage capital	(70,881)	(23,303)	(15,339)
Equity distribution to noncontrolling interest	(2,456)	(2,806)	(4,413)
Other	(418)	(372)	(328)
Net cash provided by (used in) financing activities	**(192,309)**	**(43,682)**	**43,226**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**18,306**	**(13,822)**	**(23,375)**
Cash, cash equivalents and restricted cash and investments – beginning	**113,768**	**127,590**	**150,965**
Cash, cash equivalents and restricted cash and investments – ending	**$ 132,074**	**$ 113,768**	**$ 127,590**
Supplemental cash flow information:			
Cash paid for interest	$ 152,570	$ 161,460	$ 161,809
Cash paid for income taxes	$ —	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 440	$ (96)	$ (44)

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

Tri-State Generation and Transmission Association, Inc.

Notes to Consolidated Financial Statements

NOTE 1 – ORGANIZATION

Tri-State Generation and Transmission Association, Inc. ("Tri-State," "we", "our," "us", or "the Association") is a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952. We have three classes of membership: Class A – utility full requirements members, Class B - utility partial requirements members, and non-utility members. We have 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 on 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.

We also sell a portion of our electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. In 2020, 2019 and 2018, total megawatt-hours sold were 17.5, 18.1 and 18.2 million, respectively, of which 90.8, 90.6 and 90.0 percent, respectively, were sold to Utility Members. Total revenue from electric sales was $1.3 billion for 2020, 2019 and 2018 of which 92.1, 92.8, and 97.3 percent in 2020, 2019 and 2018, respectively, was from Utility Member sales. Energy resources were provided by our generation and purchased power, of which 58.2, 61.5 and 58.9 percent in 2020, 2019 and 2018, respectively, were from our generation.

Revenue from one Utility Member, United Power, Inc. ("United Power"), was $215.2 million, or 18.0 percent, of our Utility Member revenue and 15.9 percent of our total operating revenues in 2020. No other Utility Member exceeded 10 percent of our Utility Member revenue or our total operating revenues in 2020.

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

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

We, including our subsidiaries, employ 1,304 people, of which 246 are subject to collective bargaining agreements. As of December 31, 2020, the collective bargaining agreements for our operations and maintenance electrical workers and clerical electrical workers on the Western Slope of Colorado with 246 employees represented will expire in April 2021 and we are actively working on renewing such agreements.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of the Association, our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 14—Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities.

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

JOINTLY OWNED FACILITIES: We own undivided interests in two jointly owned generating facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us) and the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")). Each participant in these agreements receives a portion of the total output of the 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 operating expenses is included in our consolidated financial statements. See Note 3 – Property, Plant and Equipment.

SEGMENT REPORTING: We are organized for the purpose of supplying wholesale power to our Utility Members and do so through the utilization of a portfolio of resources, including generation and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal-fired generating resources, we had direct ownership and investments in coal mines. Our Board serves as our chief operating decision maker who manages and reviews our operating results and allocates resources as one operating segment. Therefore, we have one reportable segment for financial reporting purposes.

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

IMPAIRMENT EVALUATION: Long-lived assets (property, plant and equipment, intangible assets, investments and preliminary surveys and investigation costs) that are held and used are evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment loss is recognized when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset (if any) are less than the carrying value of the asset. When an impairment loss is recognized, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques. In 2020, we recognized an impairment loss of $274.6 million associated with the early retirement of the Escalante Generating Station, and in 2019, we recognized an impairment loss of $37.1 million associated with the early retirement of Nucla Generating Station. These impairment losses were deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board and subject to FERC approval, if applicable. There were no impairments of long-lived assets recognized in 2018. See Note 2 – Accounting for Rate Regulation.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations in accordance with the accounting standard related to consolidation of variable interest entities. This guidance requires us to identify variable interests (contractual, ownership or other financial interests) in other entities and whether any of those entities in which we have a variable interest, meets the criteria of a variable interest entity. An entity is considered to be a variable interest entity when its total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support, or its equity investors, as a group, lack the characteristics of having a controlling financial interest. In making this assessment, we consider the potential that our arrangements and relationships with other entities provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of an entity, the ability to directly or indirectly make decisions about the entity's activities and other factors. If an entity that we have a variable interest in meets the criteria of a variable interest entity, we must determine whether we are the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct the activities of the variable interest entity that most significantly impact the variable interest entity's economic performance, and the obligation to absorb losses or the right to receive benefits from the variable interest entity that could be potentially significant to the variable interest entity. If we are determined to be the primary beneficiary of (has controlling financial interest in) a variable interest entity, then we would be required to consolidate that entity. In certain situations, it may be determined that power is shared among multiple unrelated parties such that no one party has the power to direct the activities of a variable interest entity that most significantly impact the variable interest entity's economic performance (decisions about those activities require the consent of each of the parties sharing power). In accordance with the accounting guidance prescribed by consolidation of variable interest entities, if the determination is made that power is shared among multiple unrelated parties, then no party is the primary beneficiary. See Note 14—Variable Interest Entities.

ACCOUNTING FOR RATE REGULATION: We are subject to the accounting requirements related to regulated operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board if based on regulatory orders or other available evidence, it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from our Utility Members based on rates approved by the applicable authority. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Utility Members based on rates approved by the applicable authority. Prior to September 3, 2019, our Board had sole budgetary and rate-setting authority. On September 3, 2019, we became a FERC-jurisdictional public utility and our Board's rate setting authority, including the use of regulatory assets and liabilities, is now subject to FERC approval. 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):

	December 31, 2020	December 31, 2019
Regulatory assets		
Deferred income tax expense (1)	$ 19,641	$ 58,937
Deferred prepaid lease expense – Springerville Unit 3 Lease (2)	81,424	83,714
Goodwill – J.M. Shafer (3)	46,296	49,145
Goodwill – Colowyo Coal (4)	36,161	37,194
Deferred debt prepayment transaction costs (5)	132,302	140,931
Deferred Holcomb expansion impairment loss (6)	88,819	93,494
Unrecovered plant (7)	305,625	33,864
Total regulatory assets	710,268	497,279
Regulatory liabilities		
Interest rate swap - realized gain (8) and other	3,293	3,744
Deferred revenues (9)	63,717	75,853
Membership withdrawal (10)	157,943	42,572
Total regulatory liabilities	224,953	122,169
Net regulatory asset	$ 485,315	$ 375,110

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.

(2) Represents deferral of the loss on acquisition related to the Springerville Generating Station Unit 3 ("Springerville Unit 3") prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP ("Springerville Partnership") in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Utility Members in rates.

(3) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP ("TCP") 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 in 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 in 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 in rates.

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

(7) Represents deferral of the impairment losses related to the early retirement of the Nucla and Escalante Generating Stations. In July 2019, our Board took action for the early retirement of the Nucla Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement of the Nucla Generating Station, we recognized an impairment loss of $37.1 million during the third quarter of 2019. On September 19, 2019, the Nucla Generating Station was officially retired from service. The deferred impairment loss for the Nucla Generating Station is being amortized to depreciation, amortization and depletion expense over the 3.3-year period ending in December 2022 and recovered from our Utility Members in rates. In January 2020, our Board approved the early retirement of the Escalante Generating Station and the deferral of any impairment loss in accordance with accounting for rate regulation. In conjunction with the early retirement, we recognized an impairment loss of $283.0 million in 2020 (including $263.1 million of impaired assets and $19.9 million of other closure costs). The deferred impairment loss for

Escalante Generating Station will be amortized to depreciation, amortization and depletion expense beginning in 2021 through the end of 2045, which was the depreciable life of Escalante Generating Station, and is expected to be recovered from our Utility Members through rates. The annual amortization is expected to approximate 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 through reduced rates when recognized in non-member electric sales revenue in future periods.

(10) Represents the deferral of the recognition of other income recorded related to the June 30, 2016 withdrawal of a former Utility Member from membership in us and the June 30, 2020 withdrawal of Delta-Montrose Electric Association ("DMEA") from membership in us. In connection with the DMEA withdrawal, we recognized $110.2 million of other income and $5.2 million of gain on sale of assets which was subsequently deferred. The total deferred membership withdrawal income will be refunded to Utility Members through reduced rates when recognized in other income in future periods.

ELECTRIC PLANT AND DEPRECIATION: Electric plant is stated at cost. The cost of internally constructed assets includes payroll, overhead costs and interest charged during construction. Interest rates charged during construction was 4.6 percent for 2020 and 4.7 percent for 2019 and 2018. The amount of interest capitalized during construction was $6.1, $8.7 and $8.6 million during 2020, 2019 and 2018, respectively. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated. See Note 3 - Property, Plant and Equipment.

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

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

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

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

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

	December 31, 2020	December 31, 2019
Basin Electric Power Cooperative	$ 118,295	$ 117,368
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,933	11,761
National Rural Utilities Cooperative Finance Corporation - capital term certificates	15,221	15,953
CoBank, ACB	11,141	10,201
Western Fuels Association, Inc.	2,283	2,409
Other	4,102	4,253
Investments in other associations	$ 162,975	$ 161,945

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 2020, 2019 or 2018.

INVESTMENTS IN AND ADVANCES TO COAL MINES: We had direct ownership and investments in coal mines to support our coal generating resources. We were a member of Trapper Mining, Inc. ("Trapper Mining"), which is organized as a cooperative and is the owner and operator of the Trapper Mine near Craig, Colorado. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from our membership in Trapper Mining. Our investment in Trapper Mining was recorded using the equity method. In addition, we had ownership in Western Fuels Association, Inc. ("WFA"), which is an owner of Western Fuels-Wyoming, Inc. ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. Dry Fork Mine provides coal to the Laramie River Generating Station (owned by the participants of MBPP). In December 2020, we withdrew from membership in WFA. We, through our undivided interest in the jointly owned facility MBPP, advance funds to the Dry Fork Mine.

Investments in and advances to coal mines are as follows (dollars in thousands):

	December 31, 2020	December 31, 2019
Investment in Trapper Mine	$ —	$ 15,881
Advances to Dry Fork Mine	2,799	3,800
Investments in and advances to coal mines	$ 2,799	$ 19,681

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

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

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

	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 127,187	$ 83,070
Restricted cash and investments - current	205	182
Restricted cash and investments - noncurrent	4,682	30,516
Cash, cash equivalents and restricted cash and investments	$ 132,074	$ 113,768

Our Board Policy for Financial Goals and Capital Credits was revised in 2018 to provide that our Board will endeavor to fund an internally restricted cash account for the purpose of cash funding deferred revenues and incomes held as regulatory liabilities. In connection with such policy, our Board internally restricted cash in the amount of $25.5 million as of December 31, 2019 which was included in restricted cash and investments – noncurrent. Our Board may, at any time and for any reason, unrestrict any internally restricted cash. On March 10, 2020, our Board took action to unrestrict the $25.5 million balance of the restricted cash in response to volatile market conditions.

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. At December 31, 2020, the cost and estimated fair value of the investments were $0.5 million. At December 31, 2019, the cost and estimated fair value of the investments were $0.7 million.

INVENTORIES: Coal inventories at our owned generating facilities are stated at LIFO (last-in, first-out) cost and were $24.2 and $21.4 million as of December 31, 2020 and 2019, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2020, we realized lower coal fuel expense of $0.9 million as a result of a LIFO inventory liquidation at our generating facilities.

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

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 11 – Leases.

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

	December 31, 2020	December 31, 2019
Preliminary surveys and investigations	$ 12,886	$ 21,261
Advances to operating agents of jointly owned facilities	2,071	3,917
Operating lease right-of-use assets	7,985	7,622
Other	10,704	9,872
Total other deferred charges	$ 33,646	$ 42,672

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

ASSET RETIREMENT AND ENVIRONMENTAL 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 a market risk premium. As changes in estimates occur, such as mine plans, estimated costs and timing of the performance of reclamation activities, we make revisions to the asset and obligation at the appropriate discount rate. Upon settlement of an asset retirement obligation, we 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.

OTHER DEFERRED CREDITS AND OTHER LIABILITIES: In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. We will pay $30.0 million for these easements from 2021 through the individual easement terms ending between 2036 and 2040. The present value of the remaining easement payments was $20.0 and $20.5 million as of December 31, 2020 and December 31, 2019, respectively, which is recorded as other deferred credits and other liabilities.

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

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

	December 31, 2020	December 31, 2019
Transmission easements	$ 19,983	$ 20,549
Operating lease liabilities - noncurrent	1,590	1,846
Contract liabilities (unearned revenue) - noncurrent	3,702	4,217
Customer deposits	7,712	3,015
Financial liabilities - reclamation	12,081	12,091
Other	9,532	14,681
Total other deferred credits and other liabilities	$ 54,600	$ 56,399

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

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

OTHER OPERATING REVENUE: Other operating revenue consists primarily of wheeling, transmission and lease revenues, coal sales and revenue from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is received from our membership in the Southwest Power Pool, a regional transmission organization. The lease revenue is primarily from a power sales arrangement, which expired on June 30, 2019, that was required to be accounted for as an operating lease since it conveyed to a third party the right to use power generating equipment for a stated period of time. See Note 11 – Leases. Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. The associated Colowyo Mine expenses are included in coal mining and depreciation, amortization, and depletion expense on our consolidated statements of operations.

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 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. See Note 9 – Income Taxes.

INTERCHANGE POWER: We occasionally engage in interchanges, or non-cash swapping, of energy. Based on the assumption that all energy interchanged will eventually be received or delivered in-kind, interchanged energy is generally valued at the average cost of fuel to generate power. Additionally, portions of the energy interchanged are valued per contract with the utility involved in the interchange. When we are in a net energy advance position, the advanced energy balance is recorded as an asset. If we owe energy, the net energy balance owed to others is recorded as a liability. The net activity for the year is included in purchased power expense. The interchange liability balance of $2.2 and $1.6 million at December 31, 2020 and 2019, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was a credit of $0.1 million and $0.4 million in 2020 and 2019, respectively, and an expense of $0.6 million in 2018.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

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

ELECTRIC PLANT: At December 31, 2020, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	0.89 %	to	6.27 %	$ 3,691,021	$ (1,898,984)	$ 1,792,037
Transmission plant	1.11 %	to	2.09 %	1,820,994	(627,330)	1,193,664
General plant	1.46 %	to	9.53 %	490,850	(341,440)	149,410
Other	2.75 %	to	10.00 %	251,787	(123,639)	128,148
Electric plant in service (at cost)				$ 6,254,652	$ (2,991,393)	3,263,259
Construction work in progress						89,447
Electric plant						$ 3,352,706

At December 31, 2019, our investment in electric plant and the related annual rates of depreciation or amortization calculated using the straight-line method are as follows (dollars in thousands):

	Annual Depreciation Rate			Plant In Service	Accumulated Depreciation	Net Book Value
Generation plant	0.89 %	to	6.27 %	$ 3,681,886	$ (1,599,528)	$ 2,082,358
Transmission plant	1.11 %	to	2.09 %	1,679,534	(600,740)	1,078,794
General plant	1.46 %	to	9.53 %	472,592	(321,304)	151,288
Other	2.75 %	to	10.00 %	256,380	(119,898)	136,482
Electric plant in service (at cost)				$ 6,090,392	$ (2,641,470)	3,448,922
Construction work in progress						164,924
Electric plant						$ 3,613,846

At December 31, 2020, we had $18.6 million of commitments to complete construction projects, of which approximately $9.5, $5.8 and $3.4 million are expected to be incurred in 2021, 2022 and 2023, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2020 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	$ 395,265	$ 251,621	$ 643
MBPP - Laramie River Station	27.13 %	487,185	302,537	2,785
Total		$ 882,450	$ 554,158	$ 3,428

OTHER PLANT: Other plant consists of mine assets (discussed below) and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Generating Station to a third party for their use in the production of paper).

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

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

	December 31, 2020	December 31, 2019
Colowyo Mine assets	$ 415,739	$ 356,612
New Horizon Mine assets	38,388	38,949
Fort Union Mine assets	—	846
Accumulated depreciation and depletion	(132,730)	(106,337)
Net mine assets	321,397	290,070
Non-utility assets	2,797	12,644
Accumulated depreciation	(282)	(7,270)
Net non-utility assets	2,515	5,374
Net other plant	$ 323,912	$ 295,444

NOTE 4 – ASSET RETIREMENT AND ENVIRONMENTAL RECLAMATION OBLIGATIONS

Coal mines: We have asset retirement obligations for the final reclamation costs and environmental obligations for post-reclamation monitoring related to the Colowyo Mine and the New Horizon Mine. New Horizon Mine started final reclamation on June 8, 2017.

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

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

	2020	2019
Obligations at beginning of period	$ 78,914	$ 56,772
Liabilities incurred	2,527	23,290
Liabilities settled	(3,689)	(1,090)
Accretion expense	2,506	2,863
Change in cash flow estimate	57,831	(2,921)
Total obligations at end of period	$ 138,089	$ 78,914
Less current obligations at end of period	(11,044)	(2,460)
Long-term obligations at end of period	$ 127,045	$ 76,454

In 2020, we recorded an additional reclamation liability of $59.5 million. The increase in the liability was primarily related to the review of and change in acceptable post-mine topography in the overall evaluation of South Taylor pit at the Colowyo Mine. As the South Taylor Pit is nearing its end of life, we reviewed approved post-mine topography which was accepted by the Colorado Division of Reclamation, Mining and Safety for the West pit and determined a change was necessary for the South Taylor pit. 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 5 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Contract Assets

A contract asset represents an entity’s right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity’s future performance). We have no contract assets as of December 31, 2020 and December 31, 2019.

Accounts Receivable

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

Contract liabilities (unearned revenue)

A contract liability represents an entity’s obligation to transfer goods or services to a customer for which the entity has received consideration from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. We recognized $1.2 million of this unearned revenue in 2020 in other operating revenues on our consolidated statements of operations.

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

	December 31, 2020	December 31, 2019
Accounts receivable - Members	$ 96,637	$ 105,371
Other accounts receivable - trade:		
Non-member electric sales	5,231	4,727
Other	9,785	20,628
Total other accounts receivable - trade	15,016	25,355
Other accounts receivable - nontrade	5,554	2,684
Total other accounts receivable	$ 20,570	$ 28,039
Contract liabilities (unearned revenue)	$ 6,025	$ 7,041

NOTE 6 – LONG-TERM DEBT

We have $3.2 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 aggregate amount of $19.6 million as of December 31, 2020. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. All long-term debt contains certain restrictive financial covenants, including a DSR requirement on an annual basis and an ECR requirement of at least 18 percent at the end of each fiscal year. Other than long-term debt for the Springerville certificates that has a DSR requirement of at least 1.02 on an annual basis, all other long-term debt contains a DSR requirement of at least 1.10 on an annual basis.

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. We had no outstanding borrowings under the Revolving Credit Agreement as of December 31, 2020. As of December 31, 2020, we had $650 million in availability (including $500 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

On June 24, 2020, we entered into two term loan agreements. A term loan agreement was entered into with CoBank under which we issued our First Mortgage Obligations, Series 2020A consisting of a variable rate borrowing in the amount of $125 million. A term loan agreement was entered into with CFC under which we issued our First Mortgage Obligations, Series 2020B consisting of fixed rate borrowings in the amount of $50 million and variable rate borrowings in the amount of $50 million. Proceeds from the two borrowings were utilized to pay down commercial paper borrowings, repay draws outstanding under the Revolving Credit Agreement and for general corporate purposes.

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

	December 31, 2020	December 31, 2019
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 115,583	$ 73,859
2.63% to 4.43% CoBank, ACB, due through 2042	220,704	235,900
First Mortgage Obligations, Series 2017A, Tranche 1, 3.34%, due through 2029	60,000	60,000
First Mortgage Obligations, Series 2017A, Tranche 2, 3.39%, due through 2029	60,000	60,000
First Mortgage Bonds, Series 2016A, 4.25% due 2046	250,000	250,000
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	250,000	250,000
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	250,000	250,000
First Mortgage Bonds, Series 2010A, 6.00% due 2040	500,000	500,000
First Mortgage Obligations, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligations, Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligations, Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	22,000	44,000
Variable rate CFC, as determined by CFC, due through 2026	386	443
Variable rate CFC, LIBOR-based term loan, due through 2049	152,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loans, due through 2044	297,039	172,039
Pollution control revenue bonds		
Moffat County, CO, 2.00% term rate through October 2022, Series 2009, due 2036	46,800	46,800
Springerville certificates		
Series B, 7.14%, due through 2033	333,983	371,211
Total long-term debt	$ 3,308,715	$ 3,166,472
Less debt issuance costs	(25,590)	(27,412)
Less debt discounts	(9,659)	(9,906)
Plus debt premiums	14,302	15,752
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,287,768	$ 3,144,906
Less current maturities	(87,587)	(81,555)
Long-term debt	$ 3,200,181	$ 3,063,351

Annual maturities of total long-term debt adjusted for debt issuance costs, discounts and premiums at December 31, 2020 are as follows (dollars in thousands):

2021	$ 87,587
2022	93,034
2023	93,078
2024 (1)	346,069
2025	89,168
Thereafter	2,578,832
	$ 3,287,768

(1) Includes $250 million bullet maturity for the First Mortgage Bonds, Series 2014 E-1.

NOTE 7 – SHORT-TERM BORROWINGS

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

Commercial paper consisted of the following as of and for the twelve months ended December 31 (dollars in thousands):

	2020	2019
Commercial paper outstanding, net of discounts	$ —	$ 252,323
Weighted average interest rate	— %	1.88 %

At December 31, 2020, $500 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 6 – Long-Term Debt.

NOTE 8 – FAIR VALUE

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

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

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

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

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

Marketable Securities

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

	December 31, 2020		December 31, 2019	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 491	$ 478	$ 715	$ 654

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 $95.0 million and $79.0 million as of December 31, 2020 and 2019, respectively.

Debt

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

	December 31, 2020		December 31, 2019	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total long-term debt	$ 3,308,715	$ 3,908,497	$ 3,166,472	$ 3,608,341

NOTE 9 – INCOME TAXES

We had an income tax benefit of $0.5 million, $0.3 million and $0.5 million in 2020, 2019 and 2018, respectively. These income tax benefits are due to our election to receive an alternative minimum tax credit refund in lieu of recognizing bonus depreciation.

The liability method of accounting for income taxes is utilized 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 received or settled through future rate revenues.

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

	December 31, 2020	December 31, 2019
Deferred tax assets		
Safe harbor lease receivables	$ 11,604	$ 14,552
Net operating loss carryforwards	116,430	116,797
Alternative minimum tax credit carryforwards	—	308
Deferred revenues and membership withdrawal	57,704	28,185
Operating lease liabilities	123,459	131,817
Other	39,277	26,587
	348,474	318,246
Less valuation allowance	—	(30,468)
	348,474	287,778
Deferred tax liabilities		
Basis differences- property, plant and equipment	167,243	129,427
Capital credits from other associations	30,809	32,789
Deferred debt prepayment transaction costs	31,488	33,542
Operating lease right-of-use assets	133,850	136,930
Other	4,675	14,027
	368,065	346,715
Net deferred tax liability	$ (19,591)	$ (58,937)

Net deferred tax liabilities decreased by $39.3 million in 2020. Of this amount, $51,000 is recognized as a deferred income tax benefit and the balance is deferred and reflected as a decrease in the regulatory asset established for deferred income tax expense. The accounting for regulatory assets is discussed further in Note 2—Accounting for Rate Regulation. The regulatory asset balance associated with deferred income tax expense under the liability method is $19.6 million and $58.9 million at December 31, 2020 and 2019, respectively.

The reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2020	2019	2018
Federal income tax expense at statutory rate	21.00 %	21.00 %	21.00 %
State income tax expense, net of federal benefit	2.80	2.80	2.80
Patronage exclusion	(23.80)	(23.80)	(23.80)
Asset retirement obligations	(56.69)	(11.33)	3.57
Deferred revenues and membership withdrawal	(117.60)	3.23	(28.78)
Operating liabilities, net of right-of-use assets (1)	21.02	11.29	—
Valuation Allowance	(121.38)	67.24	—
Other book tax differences	71.34	(2.43)	24.42
Impairment	81.88	—	—
Regulatory treatment of deferred taxes	119.29	(68.68)	(0.46)
Effective tax rate	(2.14)%	(0.68)%	(1.25)%

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

We had taxable income of $4.5 million for 2020. At December 31, 2020, we have a federal net operating loss carryforward of $491.0 million of which pre-2018 tax years are subject to expiration periods between 2031 and 2037. We have $355.0 million of state net operating loss carryforwards subject to expiration periods between 2020 and 2037. We did not establish a valuation allowance because it is more likely than not that the benefit from the federal and state net operating losses will be realized in the future.

We file a U.S. federal consolidated income tax return and income tax returns in state jurisdictions where required. The statute of limitations remains open for federal and state returns for the years 2017 forward. We do not have any liabilities recorded for uncertain tax positions.

NOTE 10 - 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 forty-two 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. 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, subject to FERC approval. Energy and demand have the same pattern of transfer to our Utility Members and are both measurements of the electric power provided to our Utility Members. Therefore, the provision of electric power to our Utility Members is one performance obligation. Prior to our Utility Members' requirement for electric power, we do not have a contractual right to consideration as we are not obligated to provide electric power until the Utility Member requires each incremental unit of electric power. We transfer control of the electric power to our Utility Members over time and our Utility Members simultaneously receive and consume the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method, meter readings are taken at the end of each month for billing purposes, energy and demand are determined after the meter readings and Utility Members are invoiced based on the meter reading. Payments from our Utility Members are received in accordance with the wholesale electric service contracts' terms, which is less than 30 days from the invoice date. Utility Member electric sales revenue is recorded as Utility Member electric sales on our consolidated statements of operations and Accounts receivable – Members on our consolidated statements of financial position.

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):

	2020	2019	2018
Non-member electric sales:			
Long-term contracts	$ 46,172	$ 47,224	$ 45,314
Short-term contracts	44,210	42,024	41,127
Recognition (deferral) of revenue, net	12,136	6,153	(51,678)
Coal Sales	7,326	6,662	1,075
Other	46,219	44,737	49,127
Total non-member electric sales and other operating revenue	$ 156,063	$ 146,800	$ 84,965

Non-member electric sales

Revenues from electric power sales to non-members are primarily from long-term contracts and short-term market sales. We deferred $51.7 million of non-member electric sales revenue for the year ended December 31, 2018, as directed by our Board. We recognized a net of $12.1 million and $6.2 million of deferred non-member electric sales revenue for the years ended December 31, 2020 and December 31, 2019, respectively, as directed by our Board. See Note 2 – Accounting for Rate Regulation.

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 lease revenues, coal sales and revenue from supplying steam and water. Other operating revenue also includes revenue we receive from two of our Non-Utility Members. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines in the Western Interconnection (payments are received in accordance with the contract terms which is within 20 days of the date of receipt of the invoice). 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). Steam and water revenue is derived from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station (payments from the customer are received in accordance with the contract terms which is less than 15 days of receipt of the invoice). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. Lease revenue is primarily from a power sales arrangement, which expired on June 30, 2019, that was required to be accounted for as an operating lease since the arrangement conveyed the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. We have an obligation to deliver coal and progress toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

NOTE 11 – LEASES

Leasing Arrangements As Lessee

We have lease agreements as lessee for the right to use various facilities and operational assets and had a lease agreement for the right to use power generating equipment at Brush Generating Station. Under the power purchase arrangement at the Brush Generating Station that expired on December 31, 2019, we were required to account for the arrangement as an operating lease since it conveyed to us the right to direct the use of 70 megawatts at the Brush Generating Station and whereby we provided our own natural gas for generation of electricity. We did not renew this power purchase arrangement.

Rent expense for all short-term and long-term operating leases was $2.8 million in 2020 and $7.4 million in 2019. Rent expense is included in operating expenses on our consolidated statements of operations. As of December 31, 2020, there were no arrangements accounted for as finance leases.

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

	December 31, 2020	December 31, 2019
Operating leases		
Operating lease right-of-use assets	$ 9,223	$ 8,376
Less: Accumulated amortization	(1,238)	(754)
Net operating lease right-of-use assets	$ 7,985	$ 7,622
Operating lease liabilities – current	$ (526)	$ (5,533)
Operating lease liabilities – noncurrent	(1,590)	(1,846)
Total operating lease liabilities	$ (2,116)	$ (7,379)
Operating leases		
Weighted average remaining lease term (years)	7.6	9.5
Weighted average discount rate	3.84 %	3.80 %

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

Year 1	$	580
Year 2		379
Year 3		337
Year 4		304
Year 5		80
Thereafter		732
Total lease payments	$	2,412
Less imputed interest		(296)
Total	$	2,116

Leasing Arrangements As Lessor

We have lease agreements as lessor for certain operational assets and had a lease agreement as lessor for power generating equipment at the J.M. Shafer Generating Station. Under the power sales arrangement at the J.M. Shafer Generating Station that expired on June 30, 2019, we were required to account for the arrangement as an operating lease since it conveyed to a third party the right to direct the use of 122 megawatts of the 272 megawatt generating capability of the J.M. Shafer Generating Station whereby the third party provided its own natural gas for generation of electricity. The revenue from these lease agreements of $6.6 million in 2020 and $12.1 million in 2019 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 14- Variable Interest Entities. However, as the noncontrolling interest associated with this lease arrangement generates book-tax differences, a deferred tax asset and liability have been recorded. See Note 9 – Income Taxes.

NOTE 12 – RELATED PARTIES

TRAPPER MINING, INC.: We were a member of Trapper Mining. Organized as a cooperative, Trapper Mining supplied 25.7, 24.7 and 31.1 percent in 2020, 2019 and 2018, respectively, of the coal for the Yampa Project. Our 26.57 percent share of coal purchases from Trapper Mining was $20.2, $18.6 and $18.2 million in 2020, 2019 and 2018, respectively. In December 2020, upon termination of our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. Our investment in Trapper Mining was recorded using the equity method. Our membership interest in Trapper Mining of $0.0 and $15.9 million at December 31, 2020 and 2019, respectively, is included in investments in and advances to coal mines on our consolidated statements of financial position.

NOTE 13 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,304 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan (“RS Plan”) except for the 207 employees of Colowyo Coal. The RS Plan is a defined benefit pension plan qualified under Section 401(a) and tax-exempt under Section 501(a) of the Internal Revenue Code. It is considered a multiemployer plan under the accounting standards for compensation - retirement benefits. The plan sponsor’s Employer Identification Number is 53-116145 and the Plan Number is 333.

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

Our contributions to the RS Plan in each of the years 2020, 2019 and 2018 represented less than 5 percent of the total contributions made each year to the plan by all participating employers. We made contributions to the RS Plan of $27.5, $25.8 and $27.8 million in 2020, 2019 and 2018, respectively.

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

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

Our contributions to the RS Plan include contributions for substantially all of the 246 bargaining unit employees that are made in accordance with collective bargaining agreements.

For the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act ("Act") of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at both January 1, 2019 and January 1, 2018, based on the Act funding target and the Act actuarial value of assets on those dates.

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

We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan, both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. All our executive employees 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.

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):

	2020	2019
Executive benefit restoration obligation at beginning of period	$ 674	$ —
Service cost	332	116
Interest cost	434	51
Plan amendments - prior service cost	4,674	727
Benefit payments	(715)	—
Actuarial loss (gain)	1,980	(220)
Executive benefit restoration obligation at end of period	$ 7,379	$ 674
Fair value of plan assets at beginning of year	$ —	$ —
Employer contributions	6,955	—
Fair value of plan assets at end of year	$ 6,955	$ —
Net liability recognized	$ 424	$ 674

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. As of December 31, 2020, all trust assets were held in cash and cash equivalents.

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):

	2020	2019
Accumulated other comprehensive loss at beginning of period	$ (130)	$ —
Plan amendments - prior service cost	(4,674)	(220)
Amortization of prior service cost into other income	1,911	84
Unrecognized actuarial (loss) gain	(1,980)	6
Accumulated other comprehensive loss at end of period	$ (4,873)	$ (130)

DEFINED CONTRIBUTION PLAN: We have a qualified savings plan for eligible employees who may make pre-tax and after-tax contributions totaling up to 100 percent of their eligible earnings subject to certain limitations under federal law. We make no contributions for the 246 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the 225 employees of Colowyo Coal, we contribute 1 percent of an employee's eligible earnings. For the bargaining unit employees of New Horizon Mine, we match 1 percent of employee's contributions. For the employees of Colowyo Coal, we contribute 7 percent of an employee's eligible earnings and also match an employee's contributions up to 5 percent. We made contributions to the plan of $3.5 million, $3.5 million, and $4.6 million in 2020, 2019, and 2018, respectively.

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 December 31, 2020, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

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):

	2020	2019
Postretirement medical benefit obligation at beginning of period	$ 10,195	$ 8,556
Service cost	601	563
Interest cost	259	352
Benefit payments (net of contributions by participants)	(456)	(617)
Actuarial (gain) loss	(614)	1,341
Postretirement medical benefit obligation at end of period	$ 9,985	$ 10,195
Postemployment medical benefit obligation at end of period	419	375
Total postretirement and postemployment medical obligations at end of period	$ 10,404	$ 10,570

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

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

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

	2020	2019
Amounts included in accumulated other comprehensive income at beginning of period	$ (1,387)	$ 375
Amortization of actuarial (gain) loss into income	—	(342)
Amortization of prior service cost into other income	(68)	(79)
Actuarial gain (loss)	614	(1,341)
Amounts included in accumulated other comprehensive income at end of period	$ (841)	$ (1,387)

The assumptions used in the 2020 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.05 %
Initial health care cost trend (2018)	8.00 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2027
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	12.72

Changes in the assumed health care cost trend rates would impact the accumulated postretirement medical benefit obligation and the net periodic postretirement medical benefit expense as follows (dollars in thousands):

	1% Increase	1% Decrease
Accumulated postretirement medical benefit obligation	1,233	(1,046)
Net periodic postretirement medical benefit expense	155	(128)

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

2021	$ 591
2022	603
2023	587
2024	599
2025	590
2025 through 2029	2,945
	$ 5,915

NOTE 14 – 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):

	December 31, 2020	December 31, 2019
Net electric plant	$ 758,273	$ 776,411
Noncontrolling interest	114,852	111,717
Long-term debt	342,355	380,867
Accrued interest	9,942	11,050

Our consolidated statements of operations include the following Springerville Partnership expenses for the years ended December 31 (dollars in thousands):

	2020	2019	2018
Depreciation, amortization and depletion	$ 18,138	$ 18,138	$ 18,138
Interest	22,798	25,320	27,511

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

Unconsolidated Variable Interest Entities

Western Fuels Association: WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which included us. In December 2020, we withdrew from membership in WFA. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. We also received coal supplies directly from WFA for the Escalante Generating Station in New Mexico. The pricing structure of the coal supply agreements with WFA is designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There is not sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFA's economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we were not the primary beneficiary of WFA and the entity is not consolidated. In December 2020, we ceased having any representation on the WFA board of directors. Our investment in WFA (including MBPP), accounted for using the cost method, was $2.4 million at December 31, 2020 and 2019 and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, Wyoming, was organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 27.13 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There is not sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact WFW's economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated. In December 2020, we ceased having any representation on the WFW board of directors. Our investment in WFW, accounted for using the cost method, was $0.1 million at December 31, 2020 and 2019 and is included in investments in other associations.

Trapper Mining, Inc.: Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We had a 26.57 percent cooperative member interest in Trapper Mining. In December 2020, upon termination our coal supply agreement with Trapper Mining, we withdrew from membership in Trapper Mining. The pricing structure of the coal supply agreements were designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provided the financial support for the operation of the Trapper Mine. There was not sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, we considered Trapper Mining a variable interest entity in which we had a variable interest. The power to direct the activities that most significantly impact Trapper Mining's economic performance (which includes operations, maintenance and reclamation activities) was shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we were not the primary beneficiary of Trapper Mining and the entity was not consolidated. We recorded our investment in Trapper Mining using the equity method. In December 2020, we ceased having any representation on the Trapper Mining board of directors. Our membership interest in Trapper Mining was $15.9 million at December 31, 2019, and is included in investments in and advances to coal mines. We had no membership interest in Trapper Mining as of December 31, 2020.

NOTE 15 – COMMITMENTS AND CONTINGENCIES

SALES: We have a resource-contingent power sales contract with Salt River Project Agricultural Improvement and Power District of 100 megawatts through August 31, 2036.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under contracts that expire between 2021 and 2041. These contracts require us to purchase a minimum quantity of coal at prices subject to escalation reflecting cost increases incurred by the suppliers due to market conditions. The coal purchase projection includes estimated future prices. As of December 31, 2020, the minimum coal to be purchased under these contracts is as follows (dollars in thousands):

2021	$	64,637
2022		11,968
2023		7,816
2024		7,361
2025		7,501
Thereafter		142,608
	$	241,891

Our coal purchases were $101.2 million in 2020, $125.4 million in 2019, and $120.5 million in 2018.

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

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

As of December 31, 2020, we have entered into renewable power purchase contracts to purchase the entire output from specified renewable facilities totaling approximately 1,521 MWs, including 674 MWs of wind-based power purchase agreements and 820 MWs of solar-based power purchase agreements that expire between 2030 and 2042.

Costs under the above electric power purchase agreements for the years ended December 31 were as follows (dollars in thousands):

	2020	2019	2018
Basin	$ 152,461	$ 145,008	$ 149,246
WAPA	72,491	72,504	72,757
Other renewables	69,255	63,677	62,721

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

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

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

GUARANTEES: We provide guarantees under specified agreements or transactions, including certain reclamation obligations of WFW and our subsidiaries. Our guarantees are for payment or performance by us. Most of the guarantees issued by us limit the exposure to a maximum stated amount. During all or part of 2020, we provided guarantees of, or self-bonds for, certain reclamation obligations of WFW and our subsidiaries. We no longer provide guarantees of, or self-bonds for, any reclamation obligations. We provide surety bonds from third party sureties for our reclamation obligations at Colowyo Mine and New Horizon Mine in accordance with Colorado requirements. The amounts of such bonds are based upon Colorado requirements and are different than the amount of liabilities recognized on our financial statements in accordance with GAAP. We no longer have any reclamation obligations associated with Trapper Mine, Dry Fork Mine or Fort Union Mine.

LEGAL:

Transmission Agreement: Pursuant to a long-term transmission agreement with another utility, such utility pays for and has firm rights to transfer power and energy across a transmission path in Colorado. Such right to payment and obligation to provide the transfer is borne equally by us and another entity. Due to the capacity of the transmission path, such utility's firm rights were curtailed. The utility disputed its obligation to pay due to the capacity of the transmission path and claimed we, along with the other entity, breached such transmission agreement. The parties reached a resolution of this matter without us incurring any liability. The resolution of this matter was subject to FERC approval. On October 20, 2020, an unexecuted version of an amended and restated transmission agreement to resolve this matter was filed with FERC for approval. On December 23, 2020, FERC accepted the amended and restated agreement, which resolved this matter.

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. The request was made to FERC to make the new tariffs retroactive to September 3, 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 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 did not impose any civil penalties on us. FERC also did not determine that our Utility Member rates and transmission service rates were just and reasonable and ordered a 206 proceeding to determine the justness and reasonableness of our rates and wholesale electric service contracts. FERC also rejected our Board Policy 115 ("BP 115") and member project contracts related to our Utility Members' election to provide up to 5 percent of their electric power requirements pursuant to their wholesale electric service contracts on the grounds that the initial filing was incomplete without Board Policy 101 ("BP 101") related to the self-supply in excess of the 5 percent annual allowance. 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. The settlement proceedings are continuing and settlement offers are being exchanged under the FERC administrative law judge's guidance and in participation with FERC staff. Any refunds to the applicable tariff rates would only apply for sales after March 26, 2020. FERC's March 20, 2020 order regarding our Jurisdictional PDO denied our requested declaration regarding the preemption of the United Power and LPEA proceedings at the COPUC stating they are not currently preempted.

On April 13, 2020, we filed a request for rehearing limited to the issue of preemption of the United Power and LPEA proceedings at the COPUC related to the contract termination payment amount as described in our Jurisdictional PDO. Requests for rehearing related to both the Jurisdictional PDO and tariff filings were filed with FERC by other parties, including United Power. 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. The August 28 Order also set aside requests for rehearing filed with FERC by other parties related to the Jurisdictional PDO. Requests for rehearing related to FERC's August 28 Order were filed with FERC by United Power and LPEA. On October 28, 2020, FERC issued an order denying the requests for rehearing filed by United Power and LPEA.

On July 1, 2020, we re-submitted our BP 101, BP 115, and all existing member project contracts with FERC for acceptance and on August 28, 2020 FERC accepted the filings effective August 31, 2020. FERC also ordered a 206 proceeding to determine whether our July 1 filed documents are just and reasonable and set them for settlement and hearing procedures, which were consolidated with the ongoing settlement and hearing procedures in effect for our Utility Members rates docket. FERC also established a refund effective date related to our July 1 filed documents of September 1, 2020. A request for rehearing related to this FERC order was filed with FERC by United Power. In November 2020, FERC issued an order addressing the arguments for rehearing raised by United Power and modified its August 28, 2020 order with the same result in the proceeding. United Power has 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 acceptance of our July 1 filed documents and such matter is being held in abeyance pending resolution of the Jurisdictional PDO appeal discussed below.

On July 13, 2020, we filed a petition for review with the D.C. Circuit Court of Appeals to protect our interest, and requested review of FERC's order granting in part and denying in part our Jurisdictional PDO and FERC's order granting rehearings for further consideration. 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, including United Power. On September 18, 2020, FERC filed to hold the appeals in abeyance. On September 29, 2020, an order was issued considering the motion to hold the case in abeyance directing the parties to file motions to govern future proceedings by January 11, 2021. FERC, United Power, and the other parties reached agreement on the procedures and schedule for the Jurisdictional PDO and abeyance on all non-Jurisdictional PDO matters and such filing was made to the D.C. Circuit Court of Appeals.

It is not possible to predict if FERC will require us to refund amounts to our customers for sales after March 26, 2020, if FERC will approve our current practices regarding use of regulatory assets are just and reasonable, or to estimate any liability associated with these matters. 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 proceeding 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. We filed a response on September 29, 2020. 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 November 25, 2020, LPEA and United Power jointly filed an application for rehearing, reargument, and reconsideration with the COPUC of its October 22, 2020 decision. The COPUC denied LPEA's and United Power's November 25 application, which denial became final on December 28, 2020. 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's Adams District Court Complaints: 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. United Power filed its response on July 30, 2020. 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 the claims from its November 2020 complaint, discussed below, into its amended complaint and to dismiss the November 2020 complaint against us. The court has not yet decided whether United Power will be granted leave to file its amended complaint.

In addition, on November 23, 2020, United Power filed a Complaint for Declaratory Relief in the Adams County District Court, 2020CV031496, against us seeking for the court to declare that our addition of the Non-Utility Members violated Colorado law. On December 11, 2020, we moved to dismiss United Power's November 2020 compliant because it repeats the claims pending in the May 2020 complaint proceeding. The court has not yet ruled on our motion. It is not possible to predict the outcome of these matters or whether we will incur any liability in connection with these matters.

NOTE 16 – QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2020 and 2019 are presented below. Results for the interim periods may fluctuate as a result of seasonal weather conditions, changes in rates and other factors. In the opinion of management, all adjustments (consisting of normal recurring accruals) necessary for the fair statement of our results of operations for such periods have been included (dollars in thousands):

Statement of Operations Data	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2020					
Operating revenues	$ 319,466	$ 313,656	$ 401,601	$ 317,572	$ 1,352,295
Operating margins	28,998	41,605	79,970	7,087	157,660
Net margins attributable to the Association	(4,610)	5,433	44,829	(20,531) (1)	25,121
2019					
Operating revenues	$ 339,917	$ 314,588	$ 399,053	$ 331,914	$ 1,385,472
Operating margins	40,517	34,945	77,347	13,616	166,425
Net margins attributable to the Association	6,989	(1,385)	55,145	(15,440) (2)	45,309

(1) In the fourth quarter of 2020, we recognized $12.1 million of previously deferred non-member electric sales revenue.
(2) In the fourth quarter of 2019, we recognized $6.2 million of previously deferred non-member electric sales revenue.

NOTE 17 – SUBSEQUENT EVENTS

We evaluated subsequent events through March 5, 2021, which is the date when the financial statements were issued.

As part of our decommissioning of the Escalante Generating Station and in order for McKinley Paper Company to continue its operations, McKinley Paper Company has exercised certain options under prior agreements to purchase certain of our property and retain easements for certain other property and we have agreed to sell certain additional property and provide certain additional easements to McKinley Paper Company. As of December 31, 2020, assets related to the sale were classified as electric plant held for sale on our consolidated statements of financial position. The sale of property closed on January 28, 2021.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

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