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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from to

Commission File No. 333-212006

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

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

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

Securities registered pursuant to Section 12(b) of the Act: NONE
Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☒ Yes ☐ No

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☐ Yes ☐ No (Note: The registrant is not subject to the filing requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"), but voluntarily files reports with the Securities and Exchange Commission. The registrant has filed all Exchange Act reports for the preceding 12 months (or for such shorter period that the registrant was required to file such reports)).

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer ☐ Accelerated Filer ☐ Non-Accelerated Filer ☒ Smaller Reporting Company ☐ Emerging Growth Company ☐

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

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

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

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

Documents incorporated by reference: **NONE.**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Index to 2017 Annual Report on Form 10-K

GLOSSARY

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

Abbreviations or Acronyms	Definition
BART	best available retrofit technology
Basin	Basin Electric Power Cooperative
BNSF	BNSF Railway Company
Board	Board of Directors
CERCLA, or Superfund	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFC	National Rural Utilities Cooperative Finance Corporation
Clean Water Act	Federal Water Pollution Control Act, as amended
CO_2	carbon dioxide
CoBank	CoBank, ACB
Colowyo Coal	Colowyo Coal Company L.P.
Corps	U.S. Army Corps of Engineers
Craig Station	Craig Generating Station
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DMEA	Delta-Montrose Electric Association
DM/NFR	Denver Metropolitan/North Front Range
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
EMS	Environmental Management System
EPA	Environmental Protection Agency
Elk Ridge	Elk Ridge Mining and Reclamation, LLC
Escalante Station	Escalante Generating Station
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Rating Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
IRS	Internal Revenue Service
JMEC	Jemez Mountains Electric Cooperative, Inc.
KCEC	Kit Carson Electric Cooperative, Inc.
kWh	kilowatt hour
LIBOR	London Interbank Offered Rate
MACT	maximum achievable control technology
Master Indenture	Master First Mortgage Indenture, Deed of Trust and Security Agreement, dated effective as of December 15, 1999, between us and Wells Fargo Bank, National Association, as trustee
MBPP	Missouri Basin Power Project
Members	our member distribution systems
Moody’s	Moody’s Investors Services, Inc.
MRO	Midwestern Reliability Organization
MRRE	Multi-Regional Registered Entity
MSMEC	Mora-San Miguel Electric Cooperative, Inc.
MW	Megawatt
MWh	megawatt hour
MWTG	Mountain West Transmission Group
NAAQS	National Ambient Air Quality Standard
NERC	North American Electric Reliability Corporation
NMPRC	New Mexico Public Regulation Commission

NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRECA	National Rural Electric Cooperative Association
NSPS	New Source Performance Standard
OSMRE	Office of Surface Mining Reclamation and Enforcement
PCB	polychlorinated biphenyls
PNM	Public Service Company of New Mexico
ppb	parts per billion
PSCO	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
RCRA	Resource Conservation and Recovery Act, as amended
Revolving Credit Agreement	Credit Agreement, dated as of July 29, 2011, between us and Bank of America, N.A., as administrative agent, as amended
RPS	Renewable Portfolio Standard
RS Plan	National Rural Electric Cooperative Association Retirement Security Plan
RUS	United States Department of Agriculture, Rural Utilities Service
Salt River Project	Salt River Project Agricultural Improvement and Power District
S&P	Standard & Poor's Global Ratings
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	sulfur dioxide
SPP	Southwest Power Pool, Inc.
Series 2016A Bonds	First Mortgage Bonds, Series 2016A
Springerville Partnership	Springerville Unit 3 Partnership LP
Springerville Unit 3	Springerville Generating Station Unit 3
Sunflower	Sunflower Electric Power Corporation
TCP	Thermo Cogeneration Partnership, L.P.
TEP	Tucson Electric Power Company
Trapper Mining	Trapper Mining, Inc.
Tri-State, We, Our, Us, the Association	Tri-State Generation and Transmission Association, Inc.
WAPA	Western Area Power Administration (a power marketing agency of the U.S. Department of Energy)
WECC	Western Electricity Coordinating Council
WFA	Western Fuels Association, Inc.
WFW	Western Fuels-Wyoming, Inc.
WIIN	Water Infrastructure Improvements for the Nation
WOTUS	Waters of the United States
Yampa Project	Craig Station Units 1 and 2 and related common facilities

FORWARD-LOOKING STATEMENTS

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

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

PART I

ITEM 1. BUSINESS

OVERVIEW

Our Business

Tri-State Generation and Transmission Association, Inc. is a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis serving large portions of Colorado, Nebraska, New Mexico and Wyoming. We were incorporated under the laws of the State of Colorado in 1952 as a cooperative corporation. We supply wholesale electric power to our forty-three Members, which, in turn, supply retail electric power to residential, commercial, industrial and agricultural customers.

We are owned entirely by our Members. Thirty-nine of our Members are not-for-profit, electric distribution cooperative associations. The remaining four Members are public power districts, which are political subdivisions of the State of Nebraska. The retail service territories of our Members cover approximately 200,000 square miles and their customers include suburban and rural residences, farms and ranches, and large and small businesses and industries. Our Members serve approximately 615,000 retail electric meters. Our Members are the sole state certified providers of electric service to retail (residential and business) customers within their designated service territories.

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

Including our subsidiaries, as of December 31, 2017, we employed 1,546 people, of which 319 were subject to collective bargaining agreements. As of December 31, 2017, none of these collective bargaining agreements will expire within one year.

Cooperative Structure

A cooperative is a business entity owned by its members, which are also its retail or wholesale customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As organizations acting on a not-for-profit basis, cooperatives provide services to their members on a cost effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Cooperatives generally establish rates to recover their cost-of-service and to collect a portion of revenues in excess of expenses, which constitute margins. Margins not distributed to members in cash constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors deems it appropriate to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative, current and projected capital expenditures, and the cooperative's loan and security agreements.

Electric cooperatives generally include distribution cooperatives, such as thirty-nine of our Members, and generation and transmission cooperatives, such as us. The primary purpose of electric distribution cooperatives is to supply the requirements of their retail consumers through bulk purchases of capacity and energy and to maintain a distribution system to deliver the electricity necessary to satisfy their consumers' requirements. The primary purpose of generation and transmission cooperatives is to provide wholesale electric power to their member distribution cooperatives.

Power Supply and Transmission

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating facilities. These generating facilities provide us with maximum available power of 2,808 MWs, including 1,835 MWs from coal-fired base load facilities and 973 MWs from gas/oil-fired facilities. We purchase hydroelectric power from WAPA under long-term purchase contracts which provide us with long-term power delivery from WAPA of 580 MWs during the summer and 532 MWs during the winter. We purchase additional power on a long and short-term basis, including 477 MWs under long-term purchase contracts from other renewable energy resources, including wind, solar and small hydro. We began purchasing 25 MWs of power from the Alta Luna Solar facility in January 2017 and 75 MWs of power from the Twin Buttes II Wind facility in December 2017. We transmit power to our Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers. We have ownership or capacity interests in approximately 5,562 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 378 substations and switchyards. See “PROPERTIES” for a description of our generating and transmission facilities.

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

MEMBERS

General

Our Members provide electric services, consisting of power supply and distribution services, to residential, commercial, industrial and agricultural customers in Colorado, Nebraska, New Mexico and Wyoming. Our Members' businesses involve the operation of substations, transformers and electric lines that deliver power to their customers. We currently have 43 Members after the withdrawal in June 2016 of KCEC from membership in us. Our Members and their locations are as follows:

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

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

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

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

Wholesale Electric Service Contracts

Our revenues are derived primarily from the sale of electric power to our Members pursuant to long-term wholesale electric service contracts. We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constituted approximately 96.8 percent of our revenue from Member sales in 2017) and extending through 2040 for the remaining Member (DMEA). These contracts are subject to automatic extension thereafter until either party provides at least two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive from us at least 95 percent of the power they require for the operation of their systems, except for sources, such as photovoltaic cells, fuel cells, or others that are not connected to such Member's distribution or transmission system. Each Member may elect to provide up to 5 percent of their requirements from distributed or renewable generation owned or controlled by them. As of December 31, 2017, 22 Members have enrolled in this program with capacity totaling approximately 143 MWs of which 98 MWs are in operation. In 2017, we estimate that approximately 30 percent of the energy delivered by us and our Members to our Members' customers came from non-carbon emitting resources.

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

The following table shows our Members’ aggregate coincident peak demand for the years 2013 through 2017 and the amount of energy that we supplied them:

Year	Members' Peak Demand (MW)	Amount of Energy Sold (MWh) (1)
2017	2,850	15,905,656
2016	2,802	15,746,382
2015	2,753	15,780,670
2014	2,813	15,426,603
2013	2,666	15,313,487

(1) Only includes sales to KCEC through June 30, 2016.

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

The wholesale electric service contracts we have with our Members provide that our Members shall pay us for electric service at rates and on the terms and conditions established by our Board at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of our equity. See “— RATE REGULATION.” Our Members are obligated to pay us monthly for the power, energy and transmission service we supply to them. Revenue from one Member, United Power, Inc., comprised 14.1 percent of our Member revenue and 12.1 percent of our operating revenue in 2017. No other Member exceeded 10 percent of our Member revenue or our operating revenue in 2017. Payments due to us under the wholesale electric service contracts are pledged and assigned to secure the obligations secured under our Master Indenture. A Member cannot resell at wholesale any of the electric energy delivered to it under the wholesale electric service contract, unless such resale is approved by our Board or provided for in a schedule to the wholesale electric service contract.

We and our Members are subject to regulations issued by FERC pursuant to PURPA with respect to matters involving the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. In June 2015, FERC clarified that the 5 percent limitation in our wholesale electric service contracts with our Members related to distributed or renewable generation owned or controlled by our Members did not supersede PURPA and the requirement of our Members to purchase power from qualifying facilities. In February 2016, we filed a Petition for Declaratory Order with FERC for a clarification that the fixed cost recovery mechanism in our revised Board policy is consistent with the provisions of PURPA and the implementing regulations of FERC. The revised Board policy provides for recovery of the unrecovered fixed costs directly from that Member, rather than allocating the costs among all of our Members. The fixed cost recovery is calculated based on the difference between our wholesale rate to our Members and our avoided costs. In June 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our revised Board policy. We filed a Request for Rehearing with FERC regarding FERC’s June 2016 order. We are awaiting FERC’s decision on our request for rehearing. See “Legal Proceedings.”

In July 2016, we filed on behalf of ourselves and thirty of our Members a petition for a partial waiver for FERC’s PURPA regulations. Pursuant to such petition, we will purchase capacity and energy from qualifying facilities that interconnect to distribution systems of those Members who are participating in the waiver program. We will make such purchase at a rate equal to our full avoided cost. As part of the waiver program, those participating Members will sell supplementary, back-up, and maintenance power to the qualifying facilities. We are awaiting FERC's decision on this petition for waiver.

Our Members do not have a unilateral right to exit their membership in us. Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as the Board may prescribe provided, however, that no 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.

Members' Service Territories and Customers

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

Customers. According to information we received from our Members, our Members' sales of energy in 2016 (which is the most recent information available to us) were divided by customer class as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	29.9 %	83.0 %
Large commercial	39.5	0.1
Small commercial	20.4	12.6
Irrigation	8.3	3.9
Other	1.9	0.4

From 2012 to 2016, our Members experienced an average annual compound growth rate of approximately 0.6 percent in the number of customers and an average annual compound growth rate of 1.0 percent in energy sales. In 2016, which is the most recent year with data available to us, the 15 largest customers of our Members represented 18.3 percent of electric energy sales by our Members, although no single customer of our Members represented more than 4 percent of our total energy sales. These customers are primarily in the business of minerals extraction, natural gas, CO_2, oil production, or transportation of these.

Our Members' average number of customers per mile of energized line has been stable since 2010 at approximately five customers per mile. System densities of our Members in 2016 ranged from 1.2 customers per mile to 13.7 customers per mile.

Relationship with Members

Our Members operate their systems on a not-for-profit basis. We are a cooperative corporation, and our Members are not our subsidiaries. Except with respect to the obligations of our Members under their respective wholesale electric service contracts or other agreements with us, we have no legal interest in, or obligation with respect to, any of the assets, liabilities, equity, revenue or margins of our Members, other than our rights under such wholesale electric service contracts. We have no control over or the right, ability or authority to control the electric facilities, operations, or maintenance practices of our Members. Pursuant to our Bylaws, we and our Members disclaim any intent or agreement to be a partnership, joint venture, single or joint enterprise, or any other business form, except that of a cooperative corporation and member. The revenues of our Members are not pledged to us, but are received by the respective Member and are the source from which moneys are derived by such Member to pay for capacity and energy supplied by us under the respective wholesale electric service contracts as well as from others. We occasionally have disputes with individual Members or small groups of Members, generally relating to our rates. See "LEGAL PROCEEDINGS."

Eastern and Western Interconnection

North America is comprised of two major power grids: the Western Interconnection and the Eastern Interconnection. The Western and Eastern Interconnection operate almost independently of each other with multiple direct current ties between the two grids. We have transmission facilities and serve our Members' load in both the Western and Eastern Interconnection. Approximately 4.5 percent of our total load and facilities are located in the Eastern Interconnection. Our generating facilities are located in the Western Interconnection and generally isolated from our Members' load in the Eastern Interconnection. We purchase, under a long-term purchase contract with Basin, all the power which we require to serve our Members' load in the Eastern Interconnection. See "— POWER SUPPLY RESOURCES — Purchased Power."

Competition

In accordance with state regulations, our Members have exclusive rights to provide electric service to retail customers within designated service territories. States in which our Members' service territories are located have not enacted retail competition legislation. Federal legislation could mandate retail choice in every state, but the prospect of such legislation has diminished due to a variety of factors, including the risks associated with retail competition, the state of the economy, commodity prices and the political landscape.

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

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

RATE REGULATION

General

We provide electric power to our Members at rates established by our Board. Our wholesale electric service contracts with our Members provide that rates paid by our Members for the electric power we supply to them must be set at levels sufficient to produce revenues, together with revenues from all other sources, to meet our cost of operation, including reasonable reserves, debt and lease service, and development of equity. Although our rates are generally not subject to regulation by federal, state or other governmental agencies, we are required to submit the rates to the NMPRC. We provide electric power to non-members at contractual rates under long-term arrangements and at market prices in short-term transactions. Our Board has adopted and periodically reviews and revises a Board Policy for Financial Goals and Capital Credits, which currently targets rates payable by our Members to produce financial results above the requirements of our Master Indenture. The policy may be changed by our Board at any time. Our Master Indenture requires us to establish rates that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and requires us to maintain an ECR of at least 18 percent at the end of each fiscal year.

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. Our Class A rate schedule for electric power sales to our Members consist of two billing components: an energy rate and demand rates. Member rates for energy and demand are set by our Board, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered to our Members. In 2017 (A-40 rate) and 2016 (A-39 rate), our Class A wholesale rate schedules used the same rate design. The energy rate was billed based upon a price per kwh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed on the Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays. The 2017 (A-40 rate) wholesale rate schedule increased the overall average budgeted Member revenue/kWh for 2017 by 4.23 percent compared to the overall average budgeted Member revenue/kWh for 2016.

In 2015 and 2014, our Class A wholesale rate schedule (A-38 rate) had a different rate design that incorporated seasonal average demand rates. The monthly average demand was calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The A-38 rate design also had an energy rate that incorporated an on-peak and off-peak period. We included demand response and energy shaping products in the A-38 rate schedule. The participating Member's monthly statements were adjusted using the demand response and energy shaping product incentives for Members utilizing those products. In November 2014, we implemented an optional rate (TR-1) available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015. The TR-1 optional rate had an energy rate billed based upon energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using that Member's coincident peak during our peak period in each monthly billing period during our summer peak period or our winter peak period. Three Members elected this TR-1 optional rate.

Approved by our Board in September 2017, the A-40 rate schedule will continue in effect for 2018.

Rate Policy

Pursuant to our Board Policy for Financial Goals and Capital Credits, as described above, management proposes rates that are expected to adequately recover our annual Member revenue requirements contingent upon load projections and a budget approved annually by our Board. Our Board reviews the budget and our underlying rates on an annual basis in accordance with our financial goals and rate objectives, and in accordance with the financial covenants contained in our debt instruments. The following table shows our average Member revenue/kWh for the years 2013 through 2017. The average Member revenue/kWh is our total Members electric sales revenue, including for energy, demand, and transmission, in a given year divided by the total kilowatt hours sold to our Members in that given year. The average Member revenue/kWh does not represent the actual energy and demand rate components established by our Board and paid by our Members for the years 2013 through 2017.

Year	Average Member Revenue (Cents/kWh)
2017	7.544
2016	7.207
2015	7.133
2014	7.140
2013	7.125

Under the Master Indenture, we are required to establish rates that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis. The Master Indenture also requires that we review rates promptly at any point during the year upon any material change in circumstances which was not contemplated during the annual review of Member rates.

Regulation of Rates

Our rates are established by our Board. However, we are involved in a proceeding in New Mexico which could result in oversight of our prior wholesale rates by the NMPRC. This proceeding is currently suspended for global settlement discussions regarding our prior A-37 (2013) and A-38 (2014 and 2015) Class A wholesale rate schedules payable by our Members. According to New Mexico law, we are required to file our Member rates with the NMPRC and the NMPRC only has regulatory authority over our rates in New Mexico in the event three or more of our New Mexico Members file a request to review our rates and the NMPRC finds such request to be qualified. See "MANAGEMENT'S

DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Factors Affecting Results — Rates and Regulations."

Under the FPA, electric cooperatives are not subject to rate regulation by FERC, if they are financed by RUS; they sell less than 4 million MWhs of electricity per year; or they are wholly owned by entities that are themselves not subject to rate regulation by FERC. We are not subject to FERC rate jurisdiction since each of our Members sells fewer than 4 million MWhs per year. In 2016, which is the most recent year with data available to us, our largest Member sold 2.2 million MWhs.

POWER SUPPLY RESOURCES

We provide electric power to our Members through a combination of generating facilities that we own, contract for, lease, have undivided percentage interests in or have tolling arrangements with, and through the purchase of electric power pursuant to power purchase contracts and purchases on the open market. In 2017, 61.4 percent of our energy available for sale was provided by our generation and 38.6 percent by purchased power. In 2017, we estimate that approximately 30 percent of the energy delivered by us and our Members to our Member's customers came from non-carbon emitting resources.

Generating Facilities

We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating facilities. These generating facilities provide us with maximum available power of 2,808 MWs, including 1,835 MWs from coal-fired base load facilities and 973 MWs from gas/oil-fired facilities. See "PROPERTIES" for a description of our various generating facilities.

On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement with the Colorado Department of Public Health and Environment, the EPA, WildEarth Guardians and the National Parks Conservation Association to revise the Colorado Visibility and Regional Haze State Implementation Plan. Under the proposed revision to Colorado's SIP, the owners of Craig Station Unit 1 intend to retire Craig Station Unit 1 by December 31, 2025.

As part of the above mentioned agreement on proposed revisions to Colorado's SIP, we intend to retire the Nucla Generating Station by December 31, 2022. The New Horizon Mine, which supplies coal to Nucla Generating Station, has ceased production of coal and closure activity is underway. New Horizon Mine started final reclamation on June 8, 2017. See "— ENVIRONMENTAL REGULATIONS."

We owned an 8.2 percent interest in San Juan Generating Station Unit 3, which had a capacity of 488 MWs. San Juan Unit 3 was one of the four-units at the 1,600 MW coal fired San Juan Generating Station located in the Four Corners area of New Mexico. On December 31, 2017, San Juan Generating Station Unit 3 was retired and we transferred our ownership interests to PNM and exited active participation in station operations. Our total share of San Juan Unit 3's capacity was approximately 40 MWs. We continue to have contractual cost responsibilities for a share of certain decommissioning activities for San Juan Unit 3 and reclamation responsibilities for the San Juan Mine, which supplied coal to San Juan Unit 3.

Purchased Power

We supplement our capacity and energy requirements not supplied by our generating facilities through long-term purchase contracts and short-term energy purchases. Our principal long-term power purchase contracts are with WAPA and Basin.

WAPA. Our purchases from WAPA are hydroelectric based power made at cost-based rates under long-standing federal law under which WAPA sells power to cooperatives, municipal electric systems and certain other "preference" customers. WAPA markets and transmits the power to us pursuant to three contracts, one relating to WAPA's Loveland Area Project (which terminates September 30, 2024), and two contracts relating to WAPA's Salt

Lake City Area Integrated Projects (both which terminate September 30, 2024). In 2015, we entered into a new contract with WAPA relating to the Loveland Area Project for delivery of power by WAPA beginning October 1, 2024 and ending September 30, 2054. We also expect to enter into a new contract related to Salt Lake City Area Integrated Projects for the delivery of power by WAPA beginning October 1, 2024 and ending September 30, 2057. The Loveland Area Project generally consists of generating and transmission facilities located in the Missouri River Basin. The Salt Lake City Area Integrated Projects consists of generating and transmission facilities located in the Colorado River Basin. The following table shows the long-term power delivery from WAPA in the summer season (April-September) and winter season (October-March):

Resource:	**Summer (MW)**	**Winter (MW)**
Loveland Area Projects	349	285
Salt Lake City Area/Integrated Projects	231	247
Total	580	532

Basin. Effective October 1, 2017, we entered into two new amended and restated wholesale power contracts with Basin. The new wholesale power contracts amended and restated a 1975 wholesale power contract with Basin and separated the prior 1975 wholesale power contract into two wholesale power contracts: one for the Western Interconnection and one for the Eastern Interconnection.

The wholesale power contract for the Eastern Interconnection provides the terms under which we purchase in the Eastern Interconnection all the power which we require to serve our Members' load in the Eastern Interconnection. The Members' peak load in the Eastern Interconnection in 2017 was approximately 330 MWs. Under the prior 1975 wholesale power contract, we purchased all the power which we required to serve our Members' load in Nebraska, which is primarily located in the Eastern Interconnection, in excess of power supplied by WAPA. We continue to use the power supplied by WAPA for our Members' load in the Western Interconnection.

The wholesale power contract for the Western Interconnection provides the terms under which we purchase in the Western Interconnection fixed scheduled quantities of electric power and energy. The quantity of electric power and energy varies depending on the month and hour with a maximum of 268 MWs occurring during certain hours in July. The amount of annual energy and annual monthly demand we purchase under the new wholesale power contract for the Western Interconnection remains approximately the same as the amounts we purchased in the Western Interconnection under the prior 1975 wholesale power contract.

As with the prior 1975 wholesale power contract, both new amended and restated wholesale power contracts continue through December 31, 2050 and are subject to automatic extension thereafter until either party provides at least five years' notice of its intent to terminate.

Other. In 2016, we entered into a reciprocal one year agreement with PNM that expired May 31, 2017 to sell PNM 100 MWs of power, contingent on the operation of Springerville Unit 3, and to purchase from PNM 100 MWs of power, contingent on the operation of PNM's San Juan Generating Station Unit 4. In November 2016, we also entered into a five year reciprocal agreement with PNM that commenced upon the expiration of the reciprocal one year agreement mentioned above. Similar to the one year agreement, we sell PNM 100 MWs of power, contingent on the operation of Springerville Unit 3, and purchase from PNM 100 MWs of power, contingent on the operation of PNM's San Juan Generating Station Unit 4. After the initial five year period, the agreement automatically renews for successive one year terms until terminated by either party. Both reciprocal agreements with PNM reduce our amount of needed operating reserves and reduce the amount of power we would need to purchase in the event of a forced outage of Springerville Unit 3. The net of the sales revenue and purchased power costs under both agreements is included in our purchase power expense on our consolidated statements of operations.

In addition to long-term power purchase contracts, we utilize market purchases to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost. We also utilize short-term market purchases during periods of generation outages. In addition, we have hazard sharing arrangements with

Colorado Springs Utilities, Platte River Power Authority, and TEP, which provide for supply of power to us in the event of forced outages at specified generating facilities.

Renewable Purchased Power

In addition to our contracts with WAPA for hydroelectric power purchases, we have entered into various renewable power purchase contracts to purchase the entire output from the applicable renewable facilities totaling approximately 477 MWs, including 367 MWs of wind-based power purchase agreements and 85 MWs of solar-based power purchases. The largest of these renewable power purchase contracts are summarized in the table below.

Facility Name	Location	Counterparty	Energy Source	Facility Rating (MW)	Year of Commercial Operation	Year of Contract Expiration
Alta Luna Solar	New Mexico	TPE Alta Luna, LLC	Solar	25	2017	2042
Carousel Wind Farm	Colorado	Carousel Wind Farm, LLC	Wind	150	2016	2041
Cimarron Solar	New Mexico	Southern Turner Cimarron I, LLC	Solar	30	2010	2035
Colorado Highlands Wind	Colorado	Colorado Highlands Wind, LLC	Wind	91	2012	2032
Kit Carson Windpower	Colorado	Kit Carson Windpower, LLC	Wind	51	2010	2030
San Isabel Solar	Colorado	San Isabel Solar LLC	Solar	30	2016	2041
Twin Buttes II Wind	Colorado	Twin Buttes Wind II, LLC	Wind	75	2017	2042

Power Sale Contracts

We have entered into various long-term power sales or tolling contracts with other entities totaling approximately 372 MWs, the largest of which are discussed below. We, through one of our wholly-owned subsidiaries, have an agreement that expires in June 2019 to sell PSCO 122 MWs in tolling capacity from the J.M. Shafer Generating Station. We have an agreement to sell Salt River Project 100 MWs of power, contingent on the operation of Springerville Unit 3, which expires in August 2036. We also have a five year reciprocal agreement to sell PNM 100 MWs of power, contingent on the operation of Springerville Unit 3. See "– POWER SUPPLY RESOURCES – Purchased Power." We had an agreement to sell PSCO 100 MWs of capacity through March 2017. This agreement was contingent upon the availability of capacity from Craig Station Units 1, 2, and 3, and Laramie River Generating Station Units 2 and 3.

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

Fuel Supply

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

Generating Station	Mine	Contract End Date	Annual Tonnage—Our Share (approximate)
Craig Station Units 1 and 2	Trapper Mine and Colowyo Mine	2020 and 2027, respectively	800,000
Craig Station Unit 3	Colowyo Mine	2027	1,300,000
Escalante Station	El Segundo Mine	2019	650,000 to 1,200,000
Laramie River Generating Station	Various, including Dry Fork Mine	2034	1,900,000
Nucla Generating Station	New Horizon Mine	2022	— (1)
Springerville Unit 3	North Antelope Rochelle Mine	2021	1,250,000 to 1,500,000

(1) New Horizon Mine is no longer producing coal and closure activity is underway.

Colowyo Mine: As current mining operations are completed and land is being reclaimed, Colowyo Coal is developing the Collom mining pit at the Colowyo Mine to access coal reserves for future production. In January 2017, Colowyo received final approval of the mining plan from OSMRE. Coal production from the Collom pit is expected to begin in 2019 after receipt of applicable permits.

Reclamation Liabilities. In connection with our use of coal derived from coal mining facilities in which we have an ownership interest, including the Colowyo Mine, New Horizon Mine, Trapper Mine, Dry Fork Mine, and Fort Union Mine, we have obligations for certain reclamation activities mandated by state and federal laws. These liabilities are recognized and recorded on our financial statements when required by accounting guidelines.

Natural Gas. The majority of the natural gas we purchase is for facilities used primarily to fill peak demands. We currently enter into fixed-price, fixed-quantity physical contracts for a portion of our anticipated needs, and purchase the remainder of our needs on the spot market. The majority of natural gas is purchased in the Cheyenne Hub area, which is in close proximity to the natural gas generating facilities we tend to utilize most frequently. Six major natural gas pipelines have interconnections at the Cheyenne Hub, and presently, there is adequate supply at this location. Based on the regional forecast of production activities and pipeline capacity in the Rocky Mountain region, we presently anticipate that sufficient supplies of natural gas will be available in the foreseeable future. We have several long-term natural gas transportation contracts that provide firm rights to move natural gas from various receipt points to our facilities. Finally, we may utilize financial instruments to price hedge our forecasted natural gas requirements.

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

Water Supply

We use varying amounts of water for the production of steam used to drive turbines that turn generators and produce electricity in our generating facilities.

We maintain a water portfolio that supplies water from various sources for each of our generating facilities. This portfolio is adequate to meet the water supply requirements of our generating facilities. Our generating facilities are located in the western part of the United States where demand for available water supplies is heavy, particularly in drought conditions. Litigation and disputes over water supplies are common and sometimes protracted, which can lead to uncertainty regarding any user's rights to available water supplies. If we become subject to adverse determinations in water rights litigation or to persistent drought conditions, we could be forced to acquire additional water supplies or to curtail generation at our facilities.

We are involved in a proceeding in the State of New Mexico that could impact the water rights for Escalante Station. It is an adjudication of water rights associated with the Bluewater Toltec Area to determine the past, present and future use of water rights of the Pueblos of Acoma and Laguna, which we collectively refer to as the Pueblos. Specifically, the Pueblos are seeking a determination of the volume of ground water and surface water available to them and to determine the priority of those water rights. Should the Pueblos prevail in court, permitted water rights availability for the Escalante Station will be significantly reduced, potentially requiring us to secure alternative water supplies at a cost which could potentially be higher than the cost of the water supplies currently being used.

We are also involved in proceedings in the State of Colorado that could impact the water rights of Burlington Generating Station and J.M. Shafer Generating Station. In the proceeding related to Burlington Generating Station, Plaintiff Hutton Foundation filed a complaint in the Water Court for Water Division No. 1 seeking relief that would require the state engineer to administer ground water in conjunction with surface water in order to meet Colorado's obligations under the Republican River Compact. The Water Court granted defendants' (including our) motions for summary judgment for lack of subject matter jurisdiction over two of four claims, and stayed the remaining claims pending Colorado Supreme Court review of the summary judgment order. Briefing to and oral arguments before the Colorado Supreme Court were completed in November 2017. A grant of plaintiff's requested relief could limit the availability of water to well users, including us, potentially requiring us to secure alternative water supplies at a cost which could potentially be higher than the cost of the water supplies currently being used. In the proceeding related to J.M. Shafer Generating Station, we have filed for water rights to serve the J.M. Shafer Generating Station and the application is pending in the Water Court for Water Division No. 1. The application seeks a change in water rights, among other relief. The water rights sought are for a backup supply for J.M. Shafer Generating Station, and an adverse outcome is not anticipated to substantially affect the availability of water necessary to operate the J.M. Shafer Generating Station.

Resource Planning

We continuously evaluate potential resources required to serve the long-term requirements of our Members. As part of our approach to resource planning, we evaluate various resource options including the construction of new resources and long-term power purchase contracts. In evaluating future renewable portfolio additions, we monitor market conditions, tax credit expiration schedules, impacts of current renewable resources on reliable system operations and the operation of existing generation assets, transmission system capacity, our potential participation in an organized market in the Western Interconnection, and the regulatory requirements for meeting RPS. Based upon our current Member load/resource balance forecast, we anticipate the need for additional capacity after 2025.

As part of our long-term resource planning, we have acquired real estate interests and water rights for a project called the Colorado Power Project located near Holly, Colorado. Through December 2017, we have incurred development costs of approximately $71.6 million, which is primarily the cost for the purchase of certain water rights and real estate interests, in connection with the Colorado Power Project. We have not yet selected a fuel or generation technology for this development, and we have not applied for an air permit for this development.

Over the past decade, in a joint effort with Sunflower, a Kansas generation and transmission cooperative, and others, we have pursued development of approximately 895 MWs of coal-fired base load generating capacity to be located near Holcomb, Kansas, at the site of the existing Holcomb Generating Station. There were several legal challenges to the expansion of the Holcomb Generating Station, including challenges to the air permit and to the effectiveness of RUS consents to Sunflower's development contracts with us. On March 17, 2017, the Kansas Supreme Court issued a decision upholding the air permit for one unit at Holcomb Generating Station of 895 MWs. The air permit expires if construction does not commence within 18 months. Although a final decision has not been made by our Board on whether to proceed with the construction of the project, including us exercising our option to acquire the development rights, we determined during the second quarter of 2017, the probability of us entering into construction for the project was remote. Based on this determination, the costs incurred for the expansion of the Holcomb Generating Station of

$93.5 million (excluding the costs of land and water rights) were impaired. Costs incurred after June 30, 2017 related to the expansion of the Holcomb Generating Station are recorded to other operating expense.

TRANSMISSION

We have ownership or capacity interests in approximately 5,562 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 378 substations and switchyards. See "PROPERTIES" for a description of our transmission facilities.

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

In 2015, our Board approved us becoming a "transmission-owning member" of SPP, a regional transmission organization, for our transmission facilities and loads that are located in the Eastern Interconnection and constitute about 4.5 percent of our total loads and facilities. We are now subject to greater oversight by FERC, including review of our costs of providing transmission service in the Eastern Interconnection, and must comply with the requirements of SPP, which is also subject to FERC jurisdiction. On October 30, 2015, SPP filed revisions to its Open Access Transmission Tariff to add an annual transmission revenue requirement and to implement a formula rate template and implementation protocols for those Eastern Interconnection transmission facilities on behalf of us for transmission service beginning January 1, 2016. On December 30, 2015, FERC issued an order accepting the formula rate subject to refund and setting it for settlement and hearing judge procedures. The settlement and hearing commenced in 2016 and involved two parts. The first part being the formula rate determinations, which were to be settled amongst the parties, and the second part being SPP's zonal placement of our transmission facilities that are located in the Eastern Interconnection, which could not be settled and a hearing took place in November 2016. The parties settled the formula rate part of this matter and the settlement was filed with FERC on February 22, 2017 and approved by FERC on April 28, 2017. As part of this settlement, we refunded approximately $0.7 million of our transmission revenue, which we already accrued in 2016. On February 23, 2017, the Administrative Law Judge issued an initial decision on the zonal placement part recommending that FERC approve SPP's zonal placement of our transmission facilities. If FERC accepts the initial decision, no refunds will be owed by us on this part of the matter.

We, along with nine other participants, are part of an informal group known as the MWTG, which was formed to develop strategies to adapt to the changing electric industry in the Rocky Mountain region of the Western Interconnection. In January 2017, the MWTG began discussions with the SPP, to explore potential membership. In September 2017, the MWTG announced plans to commence negotiations with SPP regarding membership. This announcement initiated a formal SPP public stakeholder process. Our negotiations with SPP involve our transmission facilities, generating facilities and loads that are located in the states of Colorado and Wyoming, along with a small portion in western Nebraska and New Mexico. Our membership in a regional transmission organization in the Western Interconnection could have many benefits for our system. Each of the participating entities will have a multi-step approval process involving some combination of executive, board of director, customer, city, state, and federal approvals. Approval from FERC is also required.

FERC

The FPA authorizes FERC to oversee the sale at wholesale and transmission of electricity in interstate commerce by public utilities, as that term is defined in the FPA. We are not subject to the general "public utility" regulation of FERC under the FPA because of the exempt status of our Members. See "— RATE REGULATION." FERC requires non-public utilities such as us to comply with several requirements that are applicable to public utilities, including the requirements to provide open access transmission service and engage in regional planning of transmission facilities, as a condition of obtaining transmission service from public utilities. We are also subject to certain reporting obligations applicable to all electric utilities, other FERC orders to the extent that they apply generally to non-public utilities, and FERC's oversight with respect to transmission planning, investment and siting, reliability standards, price transparency, and market manipulation. We are subject to certain regulations issued by FERC pursuant to the Energy Policy Act of 1992 and the Energy Policy Act of 2005 with respect to the provision of certain transmission services.

Open Access Transmission Service

Use of our transmission facilities is governed by open access transmission tariffs. This arrangement flows from Order Nos. 888, 890, and 1000, which FERC issued in 1996, 2007 and 2011, respectively, as a means of promoting universal, non-discriminatory and "open" access to the nation's transmission grid. Open access generally gives all potential users of the transmission grid an equal opportunity to obtain the transmission service necessary to support purchases or sales of electric energy, thereby promoting competition in wholesale energy markets. In these orders, FERC generally required all transmission-owning public utilities to provide transmission service on an open access basis. FERC also extended the open access requirement to non-public utilities (such as us) through a reciprocity requirement whereby a non-public utility receiving transmission service under a public utility's open access tariff must provide to the transmission service provider comparable open access to the non-public utility's own transmission facilities. Thus, we are obligated to offer reciprocal service over our transmission facilities to those public utilities from which we receive open access transmission service, on a basis comparable to our use of their transmission facilities. Since 2001, we have offered transmission service under an open access tariff for service across our system on a non-discriminatory basis. Because we are not a public utility, we are not required to formally file this tariff with FERC, and our tariff rates for transmission service provided in the Western Interconnection are not subject to FERC's public utility rate review. Beginning January 1, 2016, use of our Eastern Interconnection transmission facilities is governed by the SPP open access transmission tariff and our costs of providing transmission service in the Eastern Interconnection are subject to review by FERC. If we proceed with membership in SPP for certain of our Western Interconnection transmission facilities, those facilities will be governed by the SPP open access transmission tariff and our costs of providing transmission service over those facilities in the Western Interconnection will be subject to review by FERC.

As a non-public utility, we are not required to implement the FERC Standards of Conduct which require separation between transmission operations and merchant operations (other than in connection with the reciprocity requirement described above). To ensure our compliance with the reciprocity requirement and contractual obligations relating to confidentiality and non-disclosure of protected transmission information, we have implemented FERC's Standards of Conduct procedures, including procedures for transmission data confidentiality, by creating a physical and functional separation of protected transmission data from our employees and agents engaged in merchant functions.

FERC has express, statutory authority under Section 211A of the FPA to require "unregulated transmitting utilities" (such as us) to provide transmission service to all qualified customers on an open access basis at rates and terms that are comparable to those that the utility employs in using its own system. In Order No. 890, FERC stated that it may take action under Section 211A with respect to non-public utilities that do not adopt the open access tariff modifications that FERC required public utilities to adopt. We have not been the subject of an order under Section 211A.

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

Transmission Planning

FERC has become increasingly involved in promoting the development of the transmission grid. Prior to the 1990's, most grid expansion planning was undertaken on a local basis, as utilities and, if applicable, state regulators determined which investments were appropriate to serve local customers. In Order No. 888, FERC encouraged utilities to coordinate their planning efforts with the expectation that integrated planning would better accommodate the development of regional, wholesale energy markets. In Order No. 890, FERC expressly required coordinated transmission planning, established governing principles, and cautioned that if non-public utilities did not participate in coordinated transmission planning, FERC may compel them to do so. We comply with this requirement through our participation in WECC, WestConnect, SPP, and other sub-regional transmission planning groups and processes. In Order No. 1000, FERC required all public utilities to engage in regional and interregional transmission planning and cost allocation. As it did with respect to open access transmission service, FERC stated that it may take action under Section 211A with respect to non-public utilities that do not comply with the requirements of Order No. 1000; however, FERC provides deference to non-public utilities to encourage their participation, in particular by not requiring non-public utilities to accept mandatory cost allocation. We voluntarily comply with Order No. 1000 by participating in regional and interregional transmission planning and cost allocation processes in SPP and WestConnect. In conjunction with other utilities in the surrounding geographic area, we participate in WestConnect, a voluntary organization of transmission providers committed to assessing stakeholder needs in the Southwest. The participants in WestConnect own and operate transmission systems in all or parts of the states of Arizona, New Mexico, Colorado, Wyoming, Nevada, and California. In December 2014, we signed the WestConnect Planning Participation Agreement, which governs the WestConnect Order 1000 planning process.

FERC has also provided for rate incentives for public utilities as a means of encouraging investment in new transmission facilities. Although FERC's incentive program is focused on public utilities, FERC has encouraged non-public utilities to participate in new transmission projects and has suggested that non-public utilities may propose incentives. Recent approvals by FERC of rate incentives for transmission projects in our region and elsewhere have provided us with practical guidance as to the applicability of these incentives to potential future transmission projects.

Reliability

Section 215 of the FPA authorizes FERC to oversee the reliable operation of the nation's interconnected bulk power system. In 2007, FERC approved mandatory national reliability standards for administration by NERC. The national standards apply to all utilities that own, operate, and/or use generating or transmission facilities as part of the interconnected bulk power system. As an owner, operator and user of generation and transmission facilities, we are subject to some of these reliability standards. Under the national standards, utilities must, among other things, respond to emergencies within stated time periods, maintain prescribed levels of generation reserves, and follow instructions concerning load shedding. In 2007, FERC also approved limited delegations of authority from NERC to eight regional entities. The delegations authorize each regional entity to propose regional reliability standards for their respective regions that would supplement or exceed the national standards. NERC has also delegated to the regional entities the authority to monitor and enforce compliance with the regional and national reliability standards, subject to NERC and FERC review.

We are registered in two of the eight regional entities: WECC and MRO. WECC and MRO seek to sustain and improve the reliability of the electric grid through regional coordination, standard setting, certification of grid operators, reliability assessments, coordinated regional planning and operations, and dispute resolution. In addition, our generating facilities are included in two regional reserve sharing pools: the Rocky Mountain Reserve Group and the Southwest Reserve Sharing Group. These pools facilitate sharing of generation reserves to be activated during a system emergency such as loss of a generating unit or transmission line.

We have an active compliance monitoring program that covers all aspects of our generation and transmission reliability responsibilities. We also collaborate with our Members on areas where transmission and distribution system reliability responsibilities overlap. NERC and its regional entities, including WECC and MRO, periodically audit compliance with reliability standards. In addition to audits and spot-checks (unscheduled audits), NERC and its regional entities, including WECC and MRO, also are authorized to conduct other types of investigations, including requiring annual "self-certifications" of compliance with select reliability standards. In 2015, NERC approved our participation in a new coordinated oversight program as a MRRE, whereby WECC was designated our Lead Regional Entity. The intent of the MRRE program is to streamline compliance and enforcement efforts for entities registered in multiple regions.

In 2015, we were audited by WECC and are currently undergoing a compliance audit as part of a three-year audit cycle. While some violations were cited from the 2015 audit, only minimal penalties were assessed. The minimal penalties that were assessed took into account our efforts to fully cooperate with the investigation, our commitment to take action beyond that minimally required for baseline compliance, and the fact that none of the issues individually posed a serious or substantial risk to the reliability of the bulk power system. We have continued to develop and improve our reliability compliance program.

ENVIRONMENTAL REGULATION

We are subject to various federal, state and local laws, rules and regulations with regard to the following:

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

These laws, rules and regulations often require us to undertake considerable efforts and incur substantial costs to maintain compliance and obtain licenses, permits and approvals from various federal, state and local agencies. To comply with existing environmental regulations, we expect that we will spend approximately $60 million through 2022 in efforts to maintain compliance. We estimate that we spend over $500,000 per year in permit-related fees, as well as increased operating costs to ensure compliance with environmental standards of the Clean Air Act, described below. If we fail to comply with these laws, regulations, licenses, permits or approvals, we could be held civilly or criminally liable.

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

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

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

Air Quality

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

Our facilities are currently equipped with pollution controls that limit emissions of SO_2, NOx, and particulates below the requirements of the Clean Air Act and our permits. As needed, some specified units have appropriate mercury emission controls. We have pollution control equipment on each of our generating facilities. All three units at Craig Station have scrubbers to remove SO_2, baghouses for particulate removal and low NOx burners. Craig Station Unit 2 has selective catalytic reduction equipment for NOx control. Craig Station Unit 3 has an activated carbon injection system to control mercury emissions. Escalante Station has scrubbers to remove SO_2, baghouses for particulate removal, a laser-based system to optimize combustion for NOx emissions, and an activated carbon injection system to control mercury. Springerville Unit 3 has scrubbers to remove SO_2, baghouses for particulate removal, low NOx burners and selective catalytic reduction equipment for NOx control, and an activated carbon injection system for controlling mercury emissions. Nucla Generating Station includes a circulating fluidized bed with limestone for SO_2 removal, dry sorbent injection for additional SO_2 removal, baghouses for particulate removal, and a selective non-catalytic reduction system for NOx control.

Basin, as the operator for the Laramie River Generating Station, is responsible for environmental compliance and reporting for that facility. TEP is the operator of Springerville Unit 3 and is responsible for environmental compliance of the station. Springerville Unit 3 operates under a Title V air permit that was issued for all Springerville Generating Station units. Springerville Unit 3 was designed and constructed to comply with permitted Best Available Control Technology emission standards. If liabilities arise as a result of a failure of environmental compliance at Laramie River Generating Station or Springerville Unit 3, our respective responsibility for those liabilities is governed by the operating agreements for the facilities.

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

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 and NOx emissions by reducing allowable emission rates and by allocating emission allowances to generating facilities for SO_2 emissions based on historical or calculated levels, and reducing allowable NOx emission rates. An emission allowance, which gives the holder the authority to emit one ton of SO_2 during a calendar year, is transferable and can be bought, sold or banked in the years following its issuance. Allowances are issued by the EPA. The aggregate nationwide emissions of SO_2 from all affected units are now capped at 8.95 million tons per year. We receive and hold sufficient SO_2 allowances for compliance with the acid rain program and send excess allowances back to our general account. Allowances have been issued by EPA through compliance year 2046 and we have additional general account allowances that would provide for additional years based on our current usage rate.

Greenhouse Gases and the Clean Power Plan. On October 23, 2015, the EPA published in the Federal Register a final rule regarding emission limits and emission guidelines of CO_2 for existing generating facilities in a comprehensive rule referred to as the “Clean Power Plan.” The Clean Power Plan established guidelines for states to develop plans to limit emissions of CO_2 from existing units. The goal of the rule was a reduction in CO_2 emissions from 2005 levels of 32 percent nationwide by 2030 and specifies interim emission rates phasing in between 2022 and 2029. In 2017, we estimate that approximately 30 percent of the energy delivered by us and our Members to our Members' customers came from non-carbon emitting resources and our existing generating facilities generated approximately 61.4 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired facilities. Emissions of CO_2 from our plants totaled approximately 14.6 million short tons in 2017.

We, along with 27 states, including Arizona, Colorado, Nebraska and Wyoming, other utilities and national trade organizations, filed petitions for review of the Clean Power Plan with the D.C. Circuit Court of Appeals. On February 9, 2016, the United States Supreme Court granted numerous applications to stay the Clean Power Plan pending judicial review. On September 27, 2016, the D.C. Circuit Court of Appeals heard oral arguments on the Clean Power

Plan before an en banc court. On March 28, 2017, President Trump issued an executive order directing the EPA to review the Clean Power Plan and, as appropriate, to initiate rulemaking to suspend, revise, or rescind the Clean Power Plan. On March 28, 2017, the Department of Justice filed a motion with the D.C. Circuit Court of Appeals to hold in abeyance the legal proceeding on the Clean Power Plan until the EPA conducts a review of the Clean Power Plan. On April 4, 2017, the EPA published in the Federal Register a notice that the EPA is reviewing and, if appropriate, will initiate proceedings to suspend, revise or rescind the Clean Power Plan. On April 28, 2017, the D.C. Circuit Court of Appeals granted the Department of Justice's motion to hold in abeyance the legal proceeding on the Clean Power Plan for sixty days. On August 6, 2017, the D.C. Circuit Court of Appeals issued an order to hold the legal proceeding in abeyance for sixty days and directed the EPA to file status reports at thirty-day intervals. On October 16, 2017, the EPA published a proposal to repeal the Clean Power Plan. Comments are due by April 26, 2018. If the Clean Power Plan is upheld by the courts, as finalized, it could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables) and transmission, investment in energy efficiency programs and decreased operation, or closure of coal-fired plants.

On December 18, 2017, the EPA issued an Advanced Notice of Proposed Rulemaking soliciting public comment for a possible replacement for the Clean Power Plan. We submitted comments to the EPA on February 26, 2018.

EPA also issued a final NSPS for new units, which established CO_2 emission standards for new, modified and reconstructed units. This NSPS did not create emission standards for the expansion of the Holcomb Generating Station, but states that if the expansion moves forward and it is determined that construction did not commence prior to January 8, 2014, the EPA may create a separate rule for the expansion of the Holcomb Generating Station. We, along with 25 states, other utilities and national trade organizations, filed petitions for review of the NSPS with the D.C. Circuit Court of Appeals. On March 28, 2017, President Trump issued an executive order directing the EPA to review the NSPS and as appropriate to initiate rulemaking to suspend, revise, or rescind the NSPS. On March 28, 2017, the Department of Justice filed a motion with the D.C. Circuit Court of Appeals to hold in abeyance the legal proceeding on this NSPS until the EPA conducts a review of the NSPS. On April 4, 2017, the EPA published in the Federal Register a notice that the EPA is reviewing and, if appropriate, will initiate proceedings to suspend, revise or rescind this NSPS. The DC Circuit Court has withdrawn the oral arguments from the calendar. On April 28, 2017, the D.C. Circuit Court of Appeals granted the Department of Justice's motion to hold in abeyance the legal proceeding on the NSPS for sixty days. On August 8, 2017, the D.C. Circuit Court of Appeals issued an order to hold the legal proceeding in abeyance indefinitely and directed the EPA to file status reports at ninety-day intervals beginning October 27, 2017.

Mercury and other Hazardous Air Pollutants. The Clean Air Act also provides for a comprehensive program for the control of hazardous air pollutants, including mercury. The EPA must treat mercury as a "hazardous air pollutant" subject to a requirement to install MACT in new and existing units. In 2012, the EPA finalized a MACT rulemaking with emissions standards across four categories of emissions. We are in full compliance with the rule's emission limits at our generating facilities and have the appropriate emission controls.

New Mexico, Colorado and Arizona adopted rules that require mercury monitoring and contain emission limits. Our coal-fired facilities are subject to these regulations. We have installed mercury monitors and comply with the state rules. In light of the federal rule, New Mexico repealed its state rule in 2014 and Colorado in 2015 amended its state rule to lessen the regulatory burden.

New Source Review. Section 114(a) Information Requests related to New Source Review Program Requirements. Over the past decade, the United States Department of Justice, on behalf of the EPA, has brought enforcement actions against owners of coal-fired facilities alleging violations of the New Source Review provisions of the Clean Air Act in cases where emissions increased without commensurate installation or upgrades of pollution controls. Such enforcement actions were brought against facilities after review by the EPA of operations and maintenance records of the facilities. The EPA has the authority to review such records pursuant to Section 114 of the Clean Air Act. To date, we have not been issued an information request for EPA review of the records of any of our facilities, and therefore, are not involved in any enforcement action from past operational and maintenance activities.

National Ambient Air Quality Standards. In October 2015, the EPA lowered the NAAQS for ozone from 75 ppb to 70 ppb. The J.M. Shafer Generating Station and Knutson Generating Station are located in the DM/NFR ozone nonattainment area. The DM/NFR area did not meet the 2008 ozone NAAQS of 75 ppb and this area is not anticipated to meet the 2015 ozone NAAQS that was set at 70 ppb. Currently, it is not anticipated that additional areas will be designated as nonattainment for the more stringent 2015 ozone standard. It is expected that the DM/NFR ozone nonattainment area will be required to comply with the 2015 ozone NAAQS by 2021 or 2024, pending the outcome of current monitoring data collections. Implementation of an ozone standard of 70 ppb will require the evaluation of additional emission controls for all major sources in the DM/NFR nonattainment area. Additional emissions controls may or may not be required at the J.M. Shafer Generating Station and the Knutson Generating Station. The DM/NFR area's compliance with the 2015 ozone standard will be challenging due to the significant amount of ozone that is transported into the area from international and interstate areas outside of Colorado. International and interstate transport of ozone into the DM/NFR area add to the elevated "background" ozone concentrations, which can be substantially greater in the western part of the United States. Background ozone concentrations in the western part of the United States are significantly impacted by natural or biogenic emissions and emissions from prescribed and wildland fire.

In 2010, the EPA lowered its NAAQS for SO_2 to 196 micrograms/cubic meter. As part of the second phase of the 2010 rule implementation, Craig Station completed an air quality modeling analysis in 2016 to demonstrate its compliance with the 2010 NAAQS for SO_2.

Regional Haze. On June 15, 2005, the EPA issued the Clean Air Visibility Rule, amending its 1999 Regional Haze Rule, which had established timelines for states to improve visibility in national parks and wilderness areas throughout the United States. Under the amended rule, certain types of older sources may be required to install BART and states were to establish Reasonable Progress Goals in SIPs to meet a 2064 goal of natural visibility conditions. The amended Regional Haze Rule could require additional controls for particulate matter, SO_2 and NOx emissions from utility sources.

The states were required to develop their regional haze implementation plans by December 2007, identifying the facilities that would need to undergo BART determinations. The Reasonable Progress phase of meeting the Regional Haze Rule is the development of periodic visibility goals in order to meet a 2064 goal of natural visibility conditions. The Reasonable Progress phase SIPs establish standards and a timeline for meeting visibility goals. Colorado, New Mexico, Wyoming and Arizona developed SIPs. Each state was challenged by the EPA and legal processes are in various stages of completion.

Craig Station Units 1 and 2 are subject to BART. In 2007, the State of Colorado determined that the upgraded pollution controls completed in 2004, which included replacement of electrostatic precipitator units with baghouses to increase particulate removal, upgraded scrubbers to increase SO_2 removal and the installation of low NOx burners, met the BART rule; therefore, no additional controls were necessary. The original BART determinations were part of Colorado's SIP, which was not approved by the EPA. The EPA informed Colorado that the EPA would not approve the SIP; therefore, the state launched a new SIP rulemaking effort. Colorado created a new SIP with more stringent SO_2 and NOx emission limits for Craig Station Units 1, 2 and 3. Under the existing, approved SIP, we committed to NOx emissions rates that resulted in the installation of selective catalytic reduction on Craig Station Unit 2.

The existing, approved SIP increased the stringency of emissions limits on Craig Station Units 1 and 3 (although not to the same extent as the emissions limits on Craig Station Unit 2), significantly limiting the amount of additional controls required on those units. The WildEarth Guardians and National Parks Conservation Association filed a lawsuit against EPA for approving the plan and we entered a court-ordered mediation process. The result of mediation was a settlement agreement that committed us to a NOx emission rate limit for Craig Station Unit 1 that would have required installation of selective catalytic reduction by August 31, 2021. The legislature of Colorado approved the new rule and delivered it to the EPA for review.

On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement with the Colorado Department of Public Health and Environment, the EPA, WildEarth Guardians and the National Parks Conservation Association to revise Colorado's SIP. Under the proposed revision to the SIP, the owners of Craig Station Unit 1 intend to retire Craig Station Unit 1 by December 31, 2025. No installation of selective catalytic reduction will be required prior to its retirement in order to meet a NOx emission rate limit for Craig Station Unit 1. As part of the above mentioned agreement on proposed revisions to the SIP, we intend to retire the Nucla Generating Station by December 31, 2022. Several procedural steps are required to implement the terms of the agreement, including approval by the Colorado Air Quality Control Commission, the state legislature and the EPA. A rulemaking hearing regarding the SIP and the agreement occurred with the Colorado Air Quality Control Commission in December 2016. The Colorado Air Quality Control Commission approved the SIP and submitted it to the state legislature for approval. The state legislature approved the SIP and it was submitted to the EPA for approval.

Any source that emits SO_2, NOx, and particulates and that may contribute to the degradation of visibility in national parks and wilderness areas, identified as Class I areas, could be subject to additional controls. New Mexico opted to comply with SO_2 provisions of the Regional Haze Rule by putting in place a backstop SO_2 trading program. Arizona and New Mexico evaluated NOx emission impacts on visibility and moved forward to develop Reasonable Progress rules for NOx reductions. New Mexico’s plan includes the closure of two units at San Juan Generating Station, including Unit 3, but neither state’s current plan requirements affect our current assets. Wyoming developed a SIP that required low NOx burners and overfire air at Laramie River Generating Station; however, the EPA instead proposed a Federal Implementation Plan that also requires selective catalytic reduction. The Federal Implementation Plan was under administrative and legal challenges and a tentative settlement was reached in late 2016. If the EPA confirms the proposed settlement after a 30-day public notice and comment period, requirements will include installation of selective catalytic reduction on Laramie River Generating Station Unit 1 by May 2019 and installation of selective non-catalytic reduction on Laramie River Generating Station Units 2 and 3 by December 2018.

The Regional Haze Rule requires that states assess progress under their state plans every five years, and periodically revise their SIPs every ten years. Therefore, like many environmental requirements, the Regional Haze Rule could require further reductions if needed to meet Reasonable Progress goals in the future.

State Implementation Plans. On June 12, 2015, the EPA published a final action in the Federal Register that takes action under the Clean Air Act, enacting SIP calls in states to change provisions to the current affirmative defense to civil penalties used by permitted sources, including electric utilities, in the event they have emissions during a startup, shutdown or malfunction event that are in excess of permitted limits. States retain broad discretion concerning how to revise their SIP, so long as that revision is consistent with the requirements of the Clean Air Act. The EPA issued the SIP call for 36 states, including Arizona, Colorado, New Mexico, and Wyoming. The EPA established a deadline of November 22, 2016, by which those states must have made SIP submissions to rectify the specifically identified deficiencies in their respective SIPs. Colorado completed a rulemaking process wherein the affirmative defense provisions were retained in federal court proceedings, should a federal court wish to consider the affirmative defense provisions. New Mexico and Arizona completed rulemakings wherein the affirmative defense provisions were removed from SIPs and maintained as state regulatory provisions. At this time, we cannot predict the outcome of the EPA’s consideration of these submittals.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water under the NPDES permit program. At the present time, we have the required permits under the program for all of our generating facilities. The water quality regulations require us to comply with each state’s water quality standards, including sampling and monitoring of the waters around affected plants.

As permitted by the State of Colorado under the Colorado Discharge Permit System (a delegated NPDES program), Nucla Generating Station and Rifle Generating Station each discharge process wastewater to nearby water bodies. Nucla Generating Station discharges to the San Miguel River through a pond system that was upgraded in 1997 and Rifle Generating Station discharges to a dry ditch (unnamed tributary to Dry Creek) that flows to the Colorado River. J.M. Shafer Generating Station discharges indirectly under an EPA pretreatment permit to the City of Fort Lupton wastewater treatment facility through a pond system. The EPA’s final effluent limitation guidelines rule for steam electric power generation became effective January 4, 2016, and has had minimal impact on operations at Nucla Generating Station, Rifle Generating Station, and J.M. Shafer Generating Station. Our other facilities have on-site containment ponds where water is evaporated and have no surface water discharges. We also have NPDES storm water permits for Craig Station, Nucla Generating Station and Nucla Ash Site, and Escalante Station. We maintain Stormwater Pollution Prevention Plans as required in the stormwater permits to ensure that stormwater run-off is not impacted by industrial operations. We currently have construction stormwater permits for numerous transmission line and generation construction projects. These construction permits will be terminated once adequate vegetation is established at the sites, which can take several growing seasons. Escalante Station and Pyramid Generating Station have groundwater discharge permits administered by the New Mexico Environment Department, which governs the pond systems at both facilities and on-site ash landfill at Escalante Station. The pond systems are designed to reuse or store and evaporate water.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In August 2014, the EPA issued final regulations that provided several compliance alternatives for existing plants such as using existing technologies, or adding fish protection systems. Section 316(b) is applicable to Craig Station and Nucla Generating Station; however, impacts are minor as the facilities operate closed cycle cooling systems minimizing impingement and entrainment.

In April 2014, the EPA and the Corps proposed an expansion of regulatory authority under the Clean Water Act through broadening the definition of WOTUS. We submitted comments on the proposed rule in November 2014, identifying clarifications needed on the applicability of the ditch and waste treatment system exclusions. A final redefinition of WOTUS was published in the Federal Register on June 29, 2015. In August 2015, the United States District Court for the District of North Dakota stayed the rule for the states within its district, which includes the states in which we have operations. In October 2016, the United States Court of Appeals for the Sixth Circuit issued a nationwide stay. On January 22, 2018, the United States Supreme Court issued a decision that the federal district courts have jurisdiction, rather than the appeals courts, over the various challenges filed against the rule. The effect of the United States Supreme Court's decision on the Court of Appeals for the Sixth Circuit's stay is uncertain. On March 6, 2017, the EPA published in the Federal Register a notice that it intends to revise and rescind or revise the rule. The EPA and Corps have identified a two-step process regarding the definition of WOTUS. The first was a proposal to withdraw the 2015 definition of WOTUS, which was published on July 27, 2017. We commented on September 27, 2017 in support of the proposal. The second step is expected in 2018 with a proposal to redefine WOTUS.

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

Other Environmental Matters

Coal Ash. We manage coal combustion by-products such as fly ash, bottom ash and scrubber sludge by removing excess water and placing the by-products in land-based units in a dry form. At Craig Station, the combustion by-products are used for mine land reclamation at the adjacent coal mine. At Nucla Generating Station and Escalante Station, the combustion by-products are placed in designated landfills. The mine-fill and landfills are regulated by state environmental agencies and all required permits are in place. In 2010, the EPA proposed two options for regulating combustion by-products under RCRA. One option is regulation as a solid waste under RCRA Subtitle D; the second option is regulation as a hazardous waste under Subtitle C. The EPA in December 2014 announced that it chose to pursue regulations as a solid waste under Subtitle D of RCRA. The final Coal Combustion Residual rule was published in the Federal Register on April 17, 2015. The rule contains varying deadlines for the various compliance obligations, some of which needed to be met by the initial compliance deadline of October 19, 2015. The final federal rule is self-implementing and thus affected facilities must comply with the new regulations even if states do not adopt the rule. We estimate our total costs relating to the management of such by-products to be approximately $10 million over the life of our facilities. We are meeting all initial compliance obligations that became effective on October 19, 2015. In December 2016, Congress passed the WIIN Act. The WIIN Act provides for the establishment of state and EPA permit programs for coal ash. The Act provides flexibility for states to incorporate the EPA final rule for coal combustion residuals or develop other criteria that are at least as protective as the final rule. The WIIN Act was signed into law by President Obama on December 16, 2016. At this time, we are monitoring state actions and cannot predict state actions or impacts. The EPA is expected to release a proposed rule to address several technical and compliance-related issues pursuant to a settlement from litigation about the Coal Combustion Residuals rule, and perhaps additional issues. Until that rule is proposed it is not possible to estimate impacts to our operations.

Renewable Portfolio Standards. Colorado law requires our Colorado Members to obtain at least 6 percent and 10 percent of their energy requirements from renewable sources by year end 2015 and 2020, respectively. In 2013, Colorado law was amended to add a separate RPS requirement requiring that at least 20 percent of the energy we provide to our Colorado Members at wholesale come from renewable sources by 2020 and each year thereafter. Colorado law permits us to count renewable sources utilized by our Colorado Members for their RPS requirement towards compliance with our separate RPS requirement. New Mexico law requires our New Mexico Members to obtain 5 percent of their energy requirements from renewable sources by January 1, 2015, and increase that amount by 1 percent annually until 10 percent is achieved in 2020. Under the wholesale electric service contracts with our Members, our Members may elect to provide up to 5 percent of their requirements from distributed or renewable generation owned or controlled by them. We currently provide sufficient energy from renewable sources to meet our Members' current obligations under the RPS requirements and expect to be able to continue meeting our Members' RPS obligations through 2020 to the extent a Member does not meet its obligation with renewable generation owned or controlled by such Member as permitted under our wholesale electric service contract. We expect to be able to achieve compliance with our separate RPS that requires 20 percent of the energy we provide to our Colorado Members at wholesale come from renewable sources by 2020.

Global Climate Change Regulatory Developments Outside the Clean Air Act. Consideration of laws and regulations to limit emissions of greenhouse gases is underway at the international, national, regional and state levels. International negotiations will determine what, if any, specific commitments to reduce greenhouse gas emissions will be made by all countries that are party to the United Nations Framework Convention on Climate Change, including the United States. The outcome of the 21st Conference of the Parties held by the United Nations in Paris during December 2015 is a broad international agreement based on non-binding commitments with no enforcement provisions known as the Paris Agreement; therefore, the agreement will not directly dictate any particular emission reduction obligations for United States businesses. Commitments are subject to review every five years under the agreement. The centerpiece of the United States' commitment is the Clean Power Plan, which in February 2016 was stayed by the United States Supreme Court. On July 1, 2017, President Trump announced that the United States would begin a process to withdraw from the Paris Agreement.

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

Mine Reclamation. The EPA is working with the OSMRE and state mine reclamation regulators to develop a better understanding of mine placement practices for coal ash. The OSMRE may issue a proposed rulemaking establishing requirements and standards that apply when coal ash is used during reclamation at surface coal mining operations. However, recent regulatory agendas indicate that OSMRE is not actively pursuing these plans. Until these rules might be promulgated, we cannot determine what, if any, controls we may be required to implement to comply with the regulation.

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

Endangered Species Act. Litigation from environmental groups resulted in the U.S. Fish and Wildlife Service being placed on a schedule to make determinations as to whether or not numerous species should be formally listed as threatened or endangered under the Endangered Species Act. Once listed, a species of animal or plant with threatened or endangered status may complicate, delay, and add costs to projects. Of the several hundred species involved in the litigation settlement, we estimate that approximately 30 have the potential to affect our operations. Of particular concern due to their geographic range and potential impacts to mining and transmission assets are the greater sage-grouse, the Gunnison sage-grouse, and the lesser prairie-chicken. In September 2015, the U.S. Fish and Wildlife Service determined that it was not warranted to list the greater sage-grouse under the Endangered Species Act, in large part on the basis of federal land management agency-based conservation plans. Those plans by both the Bureau of Land Management and U.S. Forest Service are now subject to a review; we have commented on the scope of Bureau of Land Management's review. The Gunnison sage-grouse was addressed in amendments to a local Bureau of Land Management Resource Management Plan; however, the U.S. Fish and Wildlife Service did not yet issue a 4(d) rule for the species. After its listing as a threatened species was vacated, the lesser prairie-chicken is now undergoing another review under the Endangered Species Act. We are monitoring each of these issues as they develop over time.

ITEM 1A. RISK FACTORS

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

Our costs of compliance with environmental laws and regulations are significant and have increased in recent years. Future environmental laws and regulations, including laws and regulations designed to address climate change, air and water quality, coal combustion byproducts and other matters may increase our compliance costs or liabilities in the future.

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.

Generally, existing environmental regulations are becoming increasingly stringent. However, the current administration is bringing a change in direction for environmental regulations. We have spent substantial amounts on capital expenditures for air pollution control and related emissions projects to achieve and maintain compliance with applicable EPA rules and regulations at our facilities. To comply with existing environmental regulations, we expect that we will spend approximately $60 million through 2022 in efforts to maintain compliance. In 2017, our existing generating facilities generated approximately 61.4 percent of our energy available for sale, a substantial percentage of which is generated by coal-fired facilities. More stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. These actions may result in substantial increases in the cost of electricity to our Members.

In 2015, the EPA finalized emission limits and emission guidelines of CO_2 for existing generating facilities in a comprehensive rule referred to as the "Clean Power Plan." The EPA's Clean Power Plan for existing generating facilities created state goals, which are to be reached through measures inside and outside of the electric power generation and transmission industry. Currently, the Clean Power Plan remains stayed by the United States Supreme Court's order. On October 16, 2017, the EPA published a proposal to repeal the Clean Power Plan. Comments are due by April 26, 2018. We expect to submit comments to the EPA. On December 18, 2017, the EPA issued a notice for public input for a possible replacement for the Clean Power Plan. Until the EPA begins implementing actions related to the repeal and replacement of the Clean Power Plan, it is impossible to predict any impact on our existing generating facilities. However, if the Clean Power Plan is upheld by the courts, as finalized, it could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables) and transmission, investment in energy efficiency programs and decreased operation, or closure of coal-fired plants.

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

There can be no assurance that we will always be in compliance with all environmental requirements. Failure to comply with existing and future requirements, even if this failure is caused by factors beyond our control, could result in civil and criminal penalties and could cause the complete temporary or permanent shutdown of individual generating units not in compliance with these regulations. Any additional federal or state environmental restrictions imposed on our operations could result in significant additional compliance costs, including capital expenditures. Such costs could affect future unit retirement and replacement decisions and may result in significant increases in the cost of electric service. The cost impact of future legislation or regulation will depend upon the specific requirements thereof and cannot be determined at this time, but could be significant.

Our ability to raise our Members' wholesale rates may be limited and we may be subject to rate regulation.

Wholesale rate increases for our Members must be approved by a majority of our Board, which is comprised of one representative from each of our 43 Members. According to New Mexico law, we are required to file our Member rates with the NMPRC and the NMPRC only has regulatory authority over our rates in New Mexico in the event three or more of our New Mexico Members file a request to review our rates and the NMPRC finds such request to be qualified. A sufficient number of our New Mexico Members filed for such review in 2012 and 2013. The procedural schedule related to such rate reviews by the NMPRC is currently suspended to allow the parties time for further negotiations towards a global settlement. See ''LEGAL PROCEEDINGS.''

Member challenges to the rates approved by our Board could make it difficult for us to adjust the wholesale rates to our Members as completely or rapidly as necessary in response to changes in our operations or market conditions, which may have an adverse effect on our results of operations and financial condition. The outcome of the rate proceeding in New Mexico, or whether a global settlement will be reached, is difficult to predict at this time. See ''MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Factors Affecting Results—Rates and Regulation.''

Future state laws could be enacted resulting in greater oversight of our rates to our Members and may limit our ability to raise our Members' wholesale rates without review or approval of applicable state commissions.

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

Wholesale electricity prices in most regions of the United States are correlated with wholesale natural gas prices. Generally, low gas prices correlate to low wholesale electricity prices and thereby could reduce the competitiveness of our coal-fired generating facilities. Sustained low natural gas prices could negatively impact the economics of operating our coal-fired generating facilities, which could cause the temporary or permanent shutdown of individual coal-fired generating facilities, and thereby significantly increase the cost of electric service we provide to our Members and affect their ability to perform their contractual obligations to us.

Changes in power generation technology could reduce demand for our electric services.

Our business model is to provide our Members with a reliable, cost-based supply of electricity. Significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, batteries, micro turbines, wind turbines and solar cells. Adoption of these technologies may continue to increase because of advancements or government subsidies reducing the cost of generating or storing electricity through these technologies to a level that is comparable with, or lower than, our cost of generating power. There is also a perception that generating electricity through these technologies is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these technologies could reduce electricity demand and the pool of customers from whom fixed costs are recovered or could cause the temporary or permanent shutdown of individual generating units, resulting in higher rates to our Members. Increased self-generation and the related use of net energy metering, which allows our Members' self-generating customers to receive bill credits for surplus power, could reduce demand for electricity from our Members. If these technologies were to develop sufficient economies of scale and we were unable to adjust our prices to reflect reduced electricity demand and increased self-generation and net energy metering, the competitiveness of our facilities, our financial condition and results of operations could be adversely affected.

Increased competition could reduce demand for our electric sales.

The electric utility industry has experienced increasing wholesale competition, enabled by deregulation and revisions to existing regulatory policies, competing energy suppliers, new technology, and other factors. The Energy Policy Act of 1992 amended the FPA to allow for increased competition among wholesale electricity suppliers and increased access to transmission services by such suppliers. On the retail side, states in which our Members' service territories are located do not have retail competition legislation. Federal legislation could mandate retail choice in every state, but the prospect of such legislation has diminished due to a variety of factors, including the risks associated with retail competition, the state of the economy, and commodity prices.

We and our Members are subject to regulations issued by FERC pursuant to PURPA with respect to matters involving the purchase of electricity from, and the sale of electricity to, qualifying facilities and co-generators. In June 2015, FERC clarified that the 5 percent limitation in our wholesale electric service contracts with our Members related to distributed or renewable generation owned or controlled by our Members did not supersede PURPA and the requirement of our Members to purchase power from qualifying facilities. An increase in the number and/or size of qualifying facilities selling electricity to our Members could reduce our electricity demand from our Members and the pool from which we recover fixed costs, resulting in higher rates to our Members and reduced access to the capital markets.

A number of other significant factors have affected electric utility operations, including the availability and cost of fuel for electric energy generation; the use of alternative fuel sources for space and water heating and household appliances; fluctuating rates of load growth; compliance with environmental and other governmental regulations; licensing and other factors affecting the construction, operation and cost of new and existing facilities; and the effects of conservation, energy management, and other governmental regulations on electric energy use. All of these factors present an increasing challenge to companies in the electric utility industry, including our Members and us, to reduce costs, increase efficiency and innovation, and improve resource management.

We may face competition as a result of the factors described above, including competition from qualifying facilities, other utilities, fuel sources or as a result of technological innovations. Technological innovations may include methods or products that allow consumers to by-pass the electric supplier, to switch fuels or to reduce consumption. These innovations may include, but are not limited to, demand response, distributed generation, energy storage and microgrids. Competition from other utilities may consist of competition from other electric companies or annexations by municipalities. If competition increases, rates to our Members may increase or our financial condition and results of operations could be adversely affected.

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

Based on the most recent information available to us, which is 2016 data, industrial and large commercial customers account for approximately 40 percent of our Members' energy sales. A large percentage of these sales are in energy production, extraction and transportation. The 15 largest customers of our Members, a substantial percentage of which are in energy production, extraction and transportation, total approximately 18.3 percent of the aggregate retail electric energy sales of our Members, based on the same 2016 data. A significant downturn in the economy or sustained low natural gas prices or other changes in business conditions could affect this sector of the energy industry and sales could decrease in the future should these industrial and large commercial customers decide to decrease their operations accordingly or elect to self-generate.

We have a substantial amount of indebtedness.

As of December 31, 2017, we had total debt and short-term borrowings outstanding of approximately $3.3 billion, of which approximately $2.8 billion was secured under our Master Indenture. We have incurred indebtedness primarily to construct, acquire, or make capital improvements to generating and transmission facilities to supply the current and projected electricity requirements of our Members and to meet our other long-term electricity supply obligations. If demand for electricity from our Members and under our long-term power sales agreements is materially less than projected, we might not generate sufficient revenue to meet the DSR and ECR requirements in our Master Indenture or to service our indebtedness. If this occurs, we may be required to raise our rates, revise our plans for capital expenditures and/or restructure our long-term commitments. These actions may adversely affect our operations, and we may be unable to generate sufficient additional revenue to pay our obligations. Further, failure to meet the ECR requirement in our Master Indenture or failure to service the indebtedness secured by the Master Indenture would result in an event of default under the Master Indenture. As a consequence, our results of operations, liquidity and financial condition could be adversely affected.

We expect we will need to construct or acquire additional generating and transmission facilities to meet our Members' demands, which may require substantial additional capital expenditures which may increase our long-term debt, or for which we may not be able to obtain financing, and may result in development uncertainties for our business.

In order to meet expected Member-system demand growth, we regularly evaluate options, including the potential development of new generating and transmission facilities and long-term purchases of power from generating facilities owned by others or new generating facilities that may be developed by others. In the years 2018 through 2022, we estimate that we may invest approximately $1.1 billion in new facilities and upgrades to our existing facilities, including, but not limited to, investment in transmission improvements, upgrades to our existing generating facilities and transmission facilities and investments in our coal mining facilities. We expect to incur additional indebtedness in connection with this capital expenditure program. The specific projects we undertake and the amount of such investments are subject to uncertainties and may be influenced by many factors, including:

- the forecasted electric demand of our Members, which is impacted by many factors including general economic conditions, and could be influenced by energy efficiency technologies and programs and other changes in electric usage such as widespread adoption of electric or hybrid vehicles;
- availability and cost of power purchase options;
- our membership in a regional transmission organization; and
- regulatory changes, such as regulation of CO_2 or other emissions or mandatory transmission regulation requiring installation of ''smart-grid'' technology, and the cost of compliance with regulatory changes.

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

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

We rely on access to short-term and long-term capital for construction of new generating and transmission facilities and as a significant source of liquidity for capital expenditures not satisfied by cash flow generated from operations. In the years 2018 through 2022, we estimate that we may invest approximately $1.1 billion in new facilities and upgrades to our existing facilities which may require us to take on additional long-term debt.

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

- market conditions generally;
- an economic downturn or recession;
- instability in the financial markets;
- a tightening of lending and borrowing standards by banks and other credit providers;
- the overall health of the energy industry and the generation and transmission cooperative sector;
- negative events in the energy industry, such as a bankruptcy of an unrelated energy company;
- war or threat of war; or
- terrorist attacks or threatened attacks on our facilities or the facilities of unrelated energy companies.

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

We are exposed to market risk, including changes in interest rates and availability of capital in credit markets. The interest rates on these future borrowings could be significantly higher than interest rates on our existing debt. As of December 31, 2017, we had $350 million of debt with variable rates, which could increase.

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

Our financial condition is largely dependent upon our Members.

Our financial condition is largely dependent upon our Members satisfying their obligations under their wholesale electric service contracts with us. In 2017, 92.3 percent of our revenues from electric sales were from our Members. We do not control the operations of our Members, and their financial condition is not tied to our results of operations. Accordingly, we are exposed to the risk that one or more of our Members could default in the performance of their obligations to us under the wholesale electric service contracts. These defaults could result from financial difficulties of one or more Members or because of intentional actions by our Members. We are also exposed to the risk that one or more of our Members may withdraw from membership in us. Pursuant to our Bylaws, a Member may withdraw from membership in us upon compliance with such equitable terms and conditions as the Board may prescribe provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. In 2016, KCEC withdrew from membership in us and paid us an early termination fee. If we underestimate the monetary value of a Member’s obligation or a significant number of our Members withdraw, our ability to satisfy our financial obligations could be adversely affected. Furthermore, if a significant portion of our Members withdraw, we may be required to prepay certain of our long-term debt. Our results of operations and financial condition could be adversely affected if a significant portion of our Members default on their obligations to us or withdraw from membership in us.

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

We obtain our fuel supplies, including coal, natural gas and oil, from a number of different suppliers, including mines in which we have ownership interests. Any disruptions in our fuel supplies, including disruptions due to weather, labor relations, permitting, regulatory matters, and environmental regulations, or other factors affecting our coal mines or fuel suppliers, could result in us having insufficient levels of fuel supplies. For example, rail transportation bottlenecks have from time to time caused transportation companies to be unable to perform their contractual obligations to deliver coal on a timely basis and have resulted in lower than normal coal inventories at certain of our generating facilities. Similar inventory shortages could occur in the future due to any of the disruptions described above. Natural gas and oil supplies can also be subject to disruption due to natural disasters and similar events. Any failure to maintain an adequate inventory of fuel supplies could require us to operate other generating facilities at higher cost or pay significantly higher prices to obtain electric power from other sources, which would have an adverse effect on our results of operations.

If we are unable to protect our information systems against service interruption, misappropriation of data or breaches of security, our operations could be disrupted and our reputation may be damaged.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. We rely on networks, information systems and other technology, including the Internet and third-party hosted servers, to support a variety of business processes and activities. We use information systems to process financial information and results of operations for internal reporting purposes and to comply with regulatory financial reporting, legal and tax requirements. Our generation and transmission assets and information technology systems, or those of our co-owned plants, could be directly or indirectly affected by deliberate or unintentional cyber incidents. These incidents may be caused by failures during routine operations such as system upgrades or user errors, as well as network or hardware failures, malicious or disruptive software, computer hackers, rogue employees or contractors, cyber-attacks by criminal groups or activist organizations, geopolitical events, natural disasters, failures or impairments of telecommunications networks, or other catastrophic events. In addition, such incidents could result in unauthorized disclosure of material confidential information.

If our technology systems are breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generation and transmission assets and our ability to effectively maintain certain internal controls over financial reporting. Further, our generation assets rely on an integrated transmission system, a disruption of which could negatively impact our ability to deliver power to our Members. A major cyber incident could result in significant business disruption and expense to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our reputation. We also may have future compliance obligations related to new mandatory and enforceable NERC reliability standards addressing the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system.

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

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

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

We are exposed to cost uncertainty in connection with our construction projects at existing generating facilities, new and existing transmission facilities, expansion of coal mines, and in connection with decommissioning of certain existing generating facilities.

Our existing facilities require ongoing capital expenditures in order to maintain efficient and reliable operations. Many of our generating facilities were constructed over 30 years ago and, as a result, may require significant capital expenditures to maintain efficiency and reliability and to comply with changing environmental requirements.

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

- shortages and inconsistent quality of equipment, materials and labor;
- permits, approvals and other regulatory matters;
- unforeseen engineering problems;
- environmental and geological conditions;
- environmental litigation;
- delays or increased costs to interconnect our facilities with transmission grids;
- unanticipated increases in cost of materials and labor; and
- performance by engineering, construction or procurement contractors.

The decommissioning of certain of our existing generating facilities before the end of their useful life is subject to substantial risks, including potential requirements to recognize a material impairment of our assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term contracts for such generating plants and facilities. Closure of any of such generating stations may force us to incur higher costs for replacement capacity and energy. The decommissioning costs may exceed our estimate, which could negatively impact results of operations and liquidity.

All of these risks could have the effect of increasing the cost of electric service we provide to our Members and, as a result, could affect their ability to perform their contractual obligations to us.

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

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

The demand for access to existing transmission lines may make it increasingly difficult in the future for us to acquire transmission capacity rights without constructing new transmission facilities. In most cases, construction of transmission lines presents numerous challenges. Environmental and state and local permitting processes may result in significant inefficiencies and delays in construction. These issues are unavoidable and are addressed through long-term planning. We typically begin planning new transmission at least 10 years in advance of the need and voluntarily participate in regional and interregional transmission planning and cost allocation discussions with neighboring transmission providers. In the event that we are unable to complete construction of planned transmission expansion, we must rely on purchases of market priced electric power, which could put increased pressure on electric rates.

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

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

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- problems resulting from an aging workforce and retirements;
- ability to maintain a knowledgeable workforce;
- availability and cost of fuel;
- fuel supply interruptions, including transportation interruptions;
- availability and cost of water;
- water supply interruptions;
- catastrophic events such as fires, earthquakes, explosions, floods or other similar occurrences; and
- compliance with mandatory reliability standards when such standards are adopted and as subsequently revised.

Unforeseen outages at our generating facilities could lead to higher costs because we may be required to purchase power in volatile electric power markets. A decrease or elimination of revenues from electric power produced by our generating facilities or an increase in the cost of operating the facilities could adversely affect our results of operation.

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

Litigation seeking to impose liability on us for the actions of our Members has increased. The plaintiffs in these actions have claimed that we are jointly liable for the actions of our Members, including under theories of partnership, joint venture, joint/common enterprise, or alter ego. The plaintiffs in these actions have also claimed that we owe them independent duties regarding our Members. We strongly dispute these claims as inconsistent with the facts and law. Although a jury determined in one case that we and one of our Members do not operate as a joint venture or joint enterprise, the jury determined we violated an independent duty owed to the plaintiffs and were 20 percent at fault as a result of the Member’s independent actions. See “LEGAL PROCEEDINGS.” There can be no assurance that a court or jury will determine in the future that we are not severally liable or jointly liable for the actions of our Members. Our results of operations and financial condition could be adversely affected if courts or juries determine we are severally or jointly liable for the actions of our Members.

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

Our electric power supply strategy relies, in part, on purchases of electric power from other power suppliers. In 2017, purchased power provided 38.6 percent of our energy requirements. These purchases consist of a combination of purchases under long-term contracts and short-term market purchases of electric power. We also rely on long-term contracts with third-parties to (a) manage our supply and transportation of fuel for our generating facilities, and (b) sell electricity we generate to non-member utilities. We are exposed to the risk that counterparties to these long-term contracts will breach their obligations to us. If this occurs, we may be forced to enter into alternative contractual arrangements or enter into short-term market transactions at then-current market prices. Purchasing electric power in the market exposes us, and consequently our Members, to market price risk because electric power prices can fluctuate substantially over short periods of time. The terms of these new arrangements may be less favorable than the terms of our current agreements, which could have an adverse effect on our results of operations.

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

Our long-term power purchase contracts include contracts with WAPA and Basin, consisting of 15.3 percent and 14.5 percent, respectively, of our Member sales in 2017. We experience favorable pricing terms under our WAPA contracts under federal laws that give preference to federal hydropower production to certain customers, including cooperatives. If the federal laws under which we receive favorable pricing were to be amended or eliminated or if WAPA were to no longer provide us with favorable pricing for any other reason, we would have to pay significantly higher prices to obtain this electric power, which could have an adverse effect on our results of operations. The prices we pay for power under the WAPA and Basin contracts are determined by WAPA and Basin, respectively, and are subject to change in accordance with the terms of the contracts. If we would have to pay significantly higher prices under these contracts, it could have an adverse effect on our results of operations.

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

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

We may be subject to physical attacks.

As operators of energy infrastructure, we may face a heightened risk of physical attacks on our electric systems. Our generation and transmission assets and systems are geographically dispersed and are often in rural or sparsely populated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Generating Facilities

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

Name	Location	% Interest Owned or Leased	Fuel Used	Unit Rating (MW)*	Our Share (MW)	Year Installed
Coal						
Craig Generating Station Unit 1	Colorado	24.0	Coal	428	103	1980
Craig Generating Station Unit 2	Colorado	24.0	Coal	428	103	1979
Craig Generating Station Unit 3	Colorado	100.0	Coal	448	448	1984
Escalante Generating Station	New Mexico	100.0	Coal	253	253	1984
Laramie River Generating Station Unit 1	Wyoming	24.1	Coal	570	0	1980
Laramie River Generating Station Unit 2	Wyoming	24.1	Coal	570	206	1981
Laramie River Generating Station Unit 3	Wyoming	24.1	Coal	570	206	1982
Springerville Generating Station Unit 3	Arizona	100.0	Coal	416	416	2006
Nucla Generating Station	Colorado	100.0	Coal	100	100	1987
Gas/Oil						
J.M. Shafer Generating Station	Colorado	100.0	Gas	272	272	1994
Burlington Generating Station	Colorado	100.0	Oil	110	110	1977
Knutson Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Limon Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Pyramid Generating Station	New Mexico	100.0	Gas/Oil	160	160	2003
Rifle Generating Station	Colorado	100.0	Gas	81	81	1986
AltaGas Brush Energy Inc.	Colorado	100.0	Gas	70	70	1994

* The Unit Rating for each generating facility is subject to seasonal fluctuations to account for various operating conditions.

Craig Generating Station. Craig Station is a three-unit, 1,304 MW coal-fired electric generating facility located near Craig, Colorado. Craig Station Units 1 and 2 and related common facilities are known as the Yampa Project and jointly owned as tenants in common by us and four other regional utilities pursuant to a participation agreement. We own a 24 percent interest in Craig Station Units 1 and 2, which each have capacity of 428 MWs, and a 100 percent interest in Craig Station Unit 3, which has a capacity of 448 MWs. We are the operating agent for all three units and are responsible for the daily management, administration and maintenance of the facility. The costs associated with operating Craig Station Units 1 and 2 are divided on a pro-rata basis among all the participants. Our total share of Craig Station's capacity is 654 MWs. On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement whereby Unit 1 is intended to be retired by December 31, 2025.

Escalante Generating Station. Escalante Station is a 253 MW coal-fired electric generating facility located near Prewitt, New Mexico. Escalante Station is wholly owned and operated by us.

Laramie River Generating Station. Laramie River Generating Station is a three-unit, 1,710 MW coal-fired electric generating facility located near Wheatland, Wyoming and operated by Basin. Laramie River Generating Station and related transmission lines are known as the MBPP, and jointly owned as tenants in common by us and five other regional utilities pursuant to a participation agreement. We own a 24.1 percent interest in the total capacity of the facility. Certain costs associated with operating the facility are divided on a pro-rata basis among the participants, while other costs are shared in proportion to the generation scheduled and energy produced for each participant. Laramie River Generating Station Unit 1 is connected to the Eastern Interconnection, while Units 2 and 3 are connected to the Western Interconnection. Our share of Laramie River Generating Station's total capacity is 412 MWs, which we receive out of Units 2 and 3.

Springerville Generating Station Unit 3. Springerville Unit 3, located in east-central Arizona, is a 416 MW unit that is part of a four-unit, 1,578 MW coal-fired electric generating facility operated by TEP. Under contractual agreements, we, as the lessee of Springerville Unit 3, are taking 416 MWs of capacity from the unit and selling 100 MWs of such capacity to Salt River Project and 100 MWs of such capacity to PNM. We own a 51 percent equity interest (including the 1 percent general partner equity interest) in Springerville Partnership, which owns Springerville Unit 3. Our leasehold interest, as the lessee of Springerville Unit 3, is subject to the lien of our Master Indenture, but Springerville Unit 3 is not subject to the lien of our Master Indenture. Springerville Unit 3 is subject to a mortgage and lien to secure the Springerville certificates.

Nucla Generating Station. Nucla Generating Station is a 100 MW coal-fired electric generating facility located near Nucla, Colorado. Nucla Generating Station is wholly owned and operated by us. On September 1, 2016, we announced as part of an agreement that we intend to retire Nucla Generating Station by December 31, 2022.

J.M. Shafer Generating Station. J.M. Shafer Generating Station is a 272 MW, natural gas fired, combined-cycle generating facility located near Fort Lupton, Colorado, which is primarily operated to provide intermediate load generating capacity. J.M. Shafer Generating Station is owned by our wholly-owned subsidiary Thermo Cogeneration Partnership, L.P. 122 MWs are sold to PSCO under a tolling agreement through June 2019 and we utilize the remaining 150 MWs of output. Our interest in J.M. Shafer Generating Station and the PSCO tolling agreement are not subject to the lien of our Master Indenture.

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

Knutson Generating Station. Knutson Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Brighton, Colorado. The units are primarily operated during periods of peak demand. Knutson Generating Station is wholly owned and operated by us.

Limon Generating Station. Limon Generating Station consists of two 70 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Limon, Colorado. The units are primarily operated during periods of peak demand. Limon Generating Station is wholly owned and operated by us.

Pyramid Generating Station. Pyramid Generating Station consists of four 40 MW simple-cycle combustion turbines that can operate on either natural gas or fuel oil and is located near Lordsburg, New Mexico. The units are primarily operated during periods of peak demand. Pyramid Generating Station is wholly owned and operated by us.

Rifle Generating Station. Rifle Generating Station is an 81 MW, natural gas fired, combined-cycle generating facility located near Rifle, Colorado, which is primarily operated during periods of peak demand. Rifle Generating Station is wholly owned and operated by us.

AltaGas Brush Energy. We have a gas tolling arrangement through December 31, 2019 with AltaGas Brush Energy Inc. to provide intermediate load generating capacity of 70 MWs. Under this tolling arrangement, we are entitled to receive the energy output of the source facility at our call, and we supply the natural gas to operate the source facility. The source facility is a combined-cycle facility located near Brush, Colorado.

Transmission

As of December 31, 2017, we own, lease, or have undivided percentage interest in transmission lines as described in the following table (estimated miles based on Geographic Information System):

Voltage	Miles
69 kV	61 miles
115 kV	3,119 miles
138 kV	184 miles
230 kV	1,116 miles
345 kV	1,082 miles
Total	5,562 miles

We are an ownership participant in the MBPP (Laramie River Generating Station) and Yampa Project (Craig Station Units 1 and 2) transmission systems and have ownership interests or capacity rights in several other transmission line participation projects. Transmission investment also includes ownership or major equipment ownership in approximately 378 substations and switchyards. All of our interests in these facilities or agreements, as applicable, are subject to the lien of our Master Indenture.

Coal Mines

We, through either our subsidiaries or our membership in third parties, have an ownership interest in the coal mines identified in the table below.

Mine	Location	% Interest Owned
Colowyo Coal Mine	Colorado	100
New Horizon Mine(1)	Colorado	100
Trapper Mine(2)	Colorado	27
Dry Fork Mine(3)	Wyoming	27
Fort Union Mine(4)	Wyoming	50

(1) New Horizon Mine is no longer producing coal and closure activity is underway.
(2) Trapper Mine is owned by Trapper Mining. We, along with certain participants, in the Yampa Project, own Trapper Mining.
(3) Dry Fork Mine is owned by WFW. We own approximately 27 percent of the dedicated reserves.
(4) Fort Union Mine is owned by us and Basin. Fort Union Mine is not being mined at this time.

ITEM 3. LEGAL PROCEEDINGS

NMPRC Proceeding. On October 19, 2012, we gave notice, as required by New Mexico law, to the NMPRC of our A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from all of our Members. In November 2012, three of our Members located in New Mexico filed protests of our rates with the NMPRC. On December 20, 2012, the NMPRC suspended the rate filing in New Mexico and appointed a hearing examiner to conduct a hearing and establish reasonable rate schedules pursuant to New Mexico law. On January 25, 2013, we filed a Complaint for Declaratory and Injunctive Relief in the Federal District Court in New Mexico asking the Court to declare the actions of the NMPRC to be in violation of the Commerce Clause of the United States Constitution. On June 26, 2013, we filed to withdraw our A-37 rate. On July 3, 2013, the NMPRC denied the filing to withdraw and ordered the A-37 rate filing to be consolidated with the A-38 rate filing described below. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our A-38 wholesale rate which was scheduled to become effective on January 1, 2014. Four Members filed protests with the NMPRC challenging the A-38 rate. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015, and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider was applied in conjunction with our 2012 wholesale rate to recover additional revenue from the New Mexico Members in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. In October 2015, the Federal District Court in New Mexico temporarily stayed the federal proceeding to allow the parties' time to negotiate a global settlement. No initial scheduling conference in the federal proceeding has been scheduled and the parties periodically file status reports with the Court. On December 9, 2015, we and the New Mexico Members filed a joint motion with the NMPRC seeking continuation of the suspension of the procedural schedule related to the rate protests to allow the parties additional time to proceed with further negotiations towards a global settlement. On January 6, 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC. As part of the global settlement, the parties seek to address the issue of our rate regulation in New Mexico, payment of capital credits, and whether we have the right to collect the amounts uncollected from our New Mexico Members as a result of the suspension of prior rate filings. We cannot predict the outcome of this matter or if a global settlement will be reached, although we do not believe this proceeding is likely to have a material adverse effect on our financial condition or our future results of operations or cash flows.

FERC Petition. On February 17, 2016, we filed a Petition for Declaratory Order with FERC seeking a declaratory order from FERC finding that the fixed cost recovery mechanism in our revised Board policy is consistent with the provisions of PURPA and the implementing regulations of FERC. The revised Board policy provides for recovery of the unrecovered fixed costs directly from a Member as a result of that Member purchasing power from a "qualifying facility" in an amount that causes it to exceed the 5 percent limitation on that Member's self-supply of power pursuant to its wholesale electric service contract, rather than allocating the costs among all of our Members. The fixed cost recovery is calculated based on the difference between our wholesale rate to our Members and our avoided costs. Various individuals and entities filed comments and four entities filed motions to intervene, including our Member, DMEA. On June 16, 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our revised Board policy. On July 18, 2016, we filed a Request for Rehearing with FERC regarding FERC's June 16 order. In addition, five other generation and transmission cooperatives filed a Request for Rehearing with FERC. We cannot predict the outcome of our July 18 request for rehearing filed with FERC.

Las Conchas Fire. In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five weeks in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, composed of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, JMEC, in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs alleged that the fire ignited when a tree growing outside JMEC's right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. Following the filing of the Amended Complaint, JMEC settled with one plaintiff group, the subrogated insurers, executing and funding the deal on December 30, 2014, and on February 7, 2015, the district court dismissed the subrogated insurers' claims against us with prejudice. After the court's dismissal, the remaining cases were Elizabeth Ora Cox, et al., v. Jemez Mountains Electric Cooperative, Inc., et al. (second amended complaint filed January 31, 2014); Norman Armijo, et al., v. Jemez Mountains Electric Cooperative, Inc., et al. (amended complaint filed January 16, 2014); Esequiel Espinoza, et al. v. Allstate Property & Casualty, et al. (amended complaint filed April 30, 2014); Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et al. (filed June 10, 2013); and Pueblo de Cochiti., et al. v. Jemez Mountains Electric Cooperative, Inc., et al. (filed June 10, 2013). The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we were also jointly liable for any negligence by JMEC under joint venture and joint enterprise theories. A jury trial commenced on September 28, 2015 on the liability aspect of this matter. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. JMEC has resolved all claims against it, and the terms of the resolution are confidential. Although we have not settled this matter, we have reached separate confidential stipulations on damages with all plaintiff groups, reserving the right to appeal liability issues. We maintain $100 million in liability insurance coverage for this matter. On September 12 and 25, 2017, we filed notices to appeal to the New Mexico Court of Appeals the determination of our liability for this matter. The plaintiffs have filed cross-appeals on their joint venture and joint enterprise claims. If we do not prevail on appeal, we expect our allocation of damages to be covered by our liability insurance. Although we cannot predict the outcome of this matter at this point in time, we do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

Water Proceedings. We are involved in a water rights proceeding in the State of New Mexico that could impact the water rights for Escalante Station. It is an adjudication of water rights associated with the Bluewater Toltec Area to determine the past, present and future use of water rights of the Pueblos of Acoma and Laguna. We are also involved in water rights proceedings in the State of Colorado that could impact the water rights of Burlington Generating Station and J.M. Shafer Generating Station. We cannot predict the outcome of these matters, although we do not believe these proceedings are likely to have a material adverse effect on our financial condition or our future results of operations. See "BUSINESS — POWER SUPPLY RESOURCES — Water Supply."

ITEM 4. MINE SAFETY DISCLOSURES

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

PART II

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

Not Applicable.

ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth our selected consolidated financial data as of the dates for the years indicated. This consolidated financial data is qualified in its entirety by and should be read in conjunction with the more detailed information and the audited financial statements, including the notes to such financial statements, and the "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	For the years ended December 31,				
	2017	2016	2015	2014	2013
Income Statement Data					
Operating revenues	$ 1,388,593	$ 1,341,096	$ 1,335,448	$ 1,395,091	$ 1,341,163
Operating expenses	(1,204,896)	(1,194,090)	(1,157,479)	(1,213,214)	(1,152,575)
Operating margins	183,697	147,006	177,969	181,877	188,588
Interest expense	(147,608)	(144,877)	(142,570)	(142,357)	(149,463)
Net margins attributable to the Association	61,656	31,748	53,413	64,236	72,912

	As of December 31,				
	2017	2016	2015	2014	2013
Balance Sheet Data:					
Total assets	$ 4,893,594	$ 4,911,291	$ 4,823,047	$ 4,654,136	$ 4,692,584
Electric plant, in service, less accumulated depreciation	3,393,824	3,321,058	3,245,786	3,064,063	2,941,860
Construction work in progress	175,567	212,081	216,279	206,097	231,374
Long-term debt	3,120,286	3,139,705	3,273,538	3,145,246	3,069,218
Patronage capital equity	1,003,020	961,364	952,082	908,669	865,379
Accumulated other comprehensive income (loss)	(210)	(286)	589	(828)	3,335
Noncontrolling interest	111,295	109,147	108,757	109,302	110,740
Total capitalization	$ 4,234,391	$ 4,209,930	$ 4,334,966	$ 4,162,389	$ 4,048,672

	For the years ended December 31,				
	2017	2016	2015	2014	2013
Other Data					
Ratio of Earnings to Fixed Charges	1.32	1.11	1.25	1.32	1.37

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

Overview

We are a taxable wholesale electric power generation and transmission cooperative operating on a not-for-profit basis. We are organized for the purpose of providing electricity to our Members that serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We currently have 43 Members after the withdrawal in June 2016 of KCEC from membership in us. We also sell a portion of our generated electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. Our Members provide retail electric service to suburban and rural residences, farms and ranches, cities, towns and suburban communities, as well as large and small businesses and industries. As of December 31, 2017, our Members served approximately 615,000 retail electric meters over a 200,000 square-mile area. In 2017, we sold 18.0 million MWhs, of which 88.3 percent was to Members. Total revenue from electric sales was $1.3 billion for 2017, of which 92.3 percent was from Member sales.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constitute approximately 96.8 percent of our revenue from Member sales in 2017) and extending through 2040 for the remaining Member (DMEA). These contracts are subject to automatic extension thereafter until either party provides at least a two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive at least 95 percent of its electric power requirements from us. Each Member may elect to provide up to 5 percent of its electric power requirements from distributed or renewable generation owned or controlled by the Member. As of December 31, 2017, 22 Members have enrolled in this program with capacity totaling approximately 143 MWs of which 98 MWs are in operation. In 2017, we estimate that approximately 30 percent of the energy delivered by us and our Members to our Members' customers came from non-carbon emitting resources.

We provide electric power to our Members at rates established by our Board. Rates to Members are designed to generate revenues sufficient to recover our cost of service and to generate margins sufficient to establish reasonable reserves and to meet or exceed certain financial requirements. We also provide electric power to non-members at contractual rates under long-term arrangements and at market prices in short-term sale transactions.

We are a taxable cooperative subject to federal and state taxation. As a taxable cooperative, we are allowed a tax exclusion for margins allocated to our Members as patronage capital.

Under the cooperative structure, margins represent the excess of revenues over expenses. Margins not distributed to Members in cash constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of our Members without interest and is retired when our Board deems it appropriate to do so. Our Master Indenture restricts our ability to retire patronage capital during an Event of Default (as defined in our Master Indenture). We must also satisfy the required ECR after giving effect to such retirement. Additionally, the Board evaluates liquidity goals and equity goals (that are a part of the Board Policy for Financial Goals and Capital Credits) in determining the timing and amount of patronage capital retirement, and if the Board determines that our financial condition will not be impaired, retained patronage capital may be retired. Historically, patronage capital has been retired in order of priority according to the year in which the patronage capital was furnished and credited; however, our Board has discretion on the order of retirement. As of December 31, 2017, patronage capital equity was $1.003 billion.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and short-term energy purchases. We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating stations. Additionally, we transmit power to our Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers. See "BUSINESS - Overview-Power Supply and Transmission" for a description of miles of transmission lines and substations.

Depending on our system requirements and contractual obligations, we are likely to both purchase and sell electric power during the same fiscal period. We purchase hydroelectric power under long-term purchase contracts.

These contracts constituted our original power resource, and they remain a cost-effective power source. We also purchase, under long-term purchase contracts with Basin, all the power which we require to serve our Members' load in the Eastern Interconnection and fixed scheduled quantities of power in the Western Interconnection. Our generating facilities are located in the Western Interconnection and generally isolated from our Members' load in the Eastern Interconnection. These long-term purchase commitments represent a majority of our electric power purchases. We purchase additional power on a long and short-term basis, including 477 MWs under long-term purchase contracts from other renewable energy resources, including wind, solar and small hydro. At the same time, we have agreed to supply electric power to non-members. In addition, we utilize market purchases to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost and routinely selling power to the short-term market after consideration of our incremental production cost when we have excess power available above our firm commitments to both Members and non-members. We also use short-term energy purchases during periods of generation outages at our facilities.

2017 Developments

We, along with nine other participants, are part of an informal group known as the MWTG, which was formed to develop strategies to adapt to the changing electric industry in the Rocky Mountain region of the Western Interconnection. In January 2017, the MWTG began discussions with the SPP to explore potential membership. In September 2017, the MWTG announced plans to commence negotiations with SPP regarding membership. This announcement initiated a formal SPP public stakeholder process. Our negotiations with SPP involve our transmission facilities, generating facilities and loads that are located in the states of Colorado and Wyoming, along with a small portion in western Nebraska and New Mexico. Our membership in a regional transmission organization in the Western Interconnection could have many benefits for our system. Each of the participating entities will have a multi-step approval process involving some combination of executive, board of director, customer, city, state, and federal approvals. Approval from the FERC is also required.

Critical Accounting Policies

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

Accounting for Rate Regulation. We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board, which has budgetary and rate-setting authority, if it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from Members based on rates approved by our Board in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses concurrent with their recovery in rates.

Leases. The accounting for lease transactions in conformity with GAAP requires management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life, in order to determine whether a lease should be classified as operating or capital. We are the lessor under a power sales arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys the right to use our power generating equipment for a stated period of time. The lease revenue from this arrangement is included in other operating revenue on our consolidated statements of operations. We are the lessee under a power purchase arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time. It is included in lease expense on our consolidated statements of operations.

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

Factors Affecting Results

Margins and Patronage Capital

We operate on a cooperative basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to meet certain financial requirements and to establish reasonable reserves. Revenues in excess of current period costs in any year are designated as net margins in our consolidated statement of operations. Net margins are treated as advances of capital by our Members and are allocated to our Members on the basis of revenue from electricity purchases from us. Net losses, should they occur, are not allocated to our Members but are offset by future margins.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. Pursuant to the policy, we target rates payable by our Members to produce financial results in excess of the requirements under our Master Indenture. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. To date, we have retired approximately $355.5 million of patronage capital to our Members.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. Our Class A rate schedule for electric power sales to our Members consist of two billing components: an energy rate and demand rates. Over the past five years, the average Member revenue/kWh, which is our total Member electric sales revenue divided by the kWhs sold, has increased at an average of 1.5 percent per year. This average increase does not represent the actual increase in the energy and demand rate components established by our Board and paid by our Members. Member rates for energy and demand are set by our Board, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through our transmission system to our Members.

In 2017 (A-40 rate) and 2016 (A-39 rate), our Class A wholesale rate schedules used the same rate design. The energy rate was billed based upon a price per kwh of physical energy delivered and the two demand rates (a generation demand and a transmission/delivery demand) were both billed on the Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays. The 2017 (A-40 rate) wholesale rate schedule increased the overall average budgeted Member revenue/kWh for 2017 by 4.23 percent compared to the overall average budgeted Member revenue/kWh for 2016.

In accordance with budgetary and rate-setting authority of the Board, as part of our Board approving the A-40 rate schedule in 2016, which was implemented on January 1, 2017, the Board approved the income recognition of $40.0 million of previously deferred regulatory liabilities for use in 2017, including $30.0 million of previously deferred non-member electric sales revenue, of which $7.5 million was being recognized per quarter, and $10.0 million of previously deferred membership withdrawal income, of which $2.5 million was being recognized per quarter. Based upon projected margins attributable to us for 2017, pursuant to the direction of our Board, no previously deferred regulatory liabilities were recognized after the six months ended June 30, 2017. Furthermore, based upon the margin attributable to us in 2017, pursuant to the direction of our Board after considering the financial goals and rate objectives set forth in the Board Policy for Financial Goals and Capital Credits, $9.5 million of fourth quarter 2017 non-member electric sales revenue was deferred.

In 2015 and 2014, our Class A wholesale rate schedule (A-38 rate) had a different rate design that incorporated seasonal average demand rates. The monthly average demand was calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The A-38 rate design also had an energy rate that incorporated an on-peak and off-peak period. We included demand response and energy shaping products to complement the A-38 rate schedule. The participating Members' monthly statements were adjusted using the demand response and energy shaping product incentives for Members utilizing those products. In November 2014, we implemented an optional rate (TR-1) available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015. The TR-1 optional rate had an energy rate billed based upon energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using that Member's coincident peak during our peak period in each monthly billing period during our summer peak period or our winter peak period. Three Members elected this TR-1 optional rate.

Approved by our Board in September 2017, the A-40 rate schedule will continue in effect for 2018.

Although rates established by our Board are generally not subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rates to the NMPRC. As discussed below, we are involved in a proceeding in New Mexico regarding efforts by the NMPRC related to our prior wholesale rates payable by our New Mexico Members. This proceeding is currently suspended for global settlement discussions.

As required by New Mexico law, we file our rates to our New Mexico Members with the NMPRC, which has regulatory authority over rate increases in New Mexico, only in the event three or more of our New Mexico Members file a request for such a review and such review is found to be qualified by the NMPRC. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our 2014 Class A wholesale rate schedule (A-38) which was scheduled to become effective on January 1, 2014. Four Members filed protests with the NMPRC challenging the A-38 rate. On December 11, 2013, the NMPRC suspended the A-38 rate filing. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through December 31, 2015 and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider was applied in conjunction with our 2012 Class A wholesale rate schedule to recover additional revenue from the New Mexico Members in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. In 2015, the overall impact of the New Mexico Members paying a lower rate was approximately $10.7 million. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 Class A wholesale rate schedule (A-39) which became effective on January 1, 2016. No New Mexico Member filed a protest with the NMPRC of our A-39 rate schedule and thus the A-39 rate schedule became effective without NMPRC review or approval. On December 9, 2015, we and the New Mexico Members filed a joint motion with the NMPRC seeking continuation of the suspension of the procedural schedule related to the rate protests to allow the parties additional time to proceed with further negotiations towards a global settlement. On January 6, 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC. On September 20, 2016, we gave notice, as required by New Mexico law, to the NMPRC of our 2017 (A-40) wholesale rate which became effective on January 1, 2017. No New Mexico Member filed a protest with the NMPRC of our A-40 rate and thus the A-40 rate became effective without NMPRC review or approval.

Master Indenture

As of December 31, 2017, we had approximately $2.8 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture.

Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a DSR of at least 1.10 on an annual basis and permits us to incur additional secured obligations as long as after giving effect to the additional secured obligation, we will continue to meet the DSR requirement on both a historic and pro forma basis. Our DSR is calculated by dividing (x) our Net Margins Available for Debt Service (as defined in our Master Indenture), which is equal to our net margins for a period plus amounts deducted for the period to pay or make provision for interest on debt (including capitalized interest other than Allowance for Funds Used During Construction), lease expense, income tax expense, amortization of debt discount or premium, and depreciation and certain other non-cash items by (y) our Annual Debt Service Requirement (as defined in our Master Indenture), which is generally equal to the principal of, premium, if any, and interest (whether capitalized or expensed) on all of our debt and lease payments which become due in the applicable fiscal year or 12-month period at maturity or stated maturity, subject to special calculation rules applicable to specific types of debt (such as balloon debt). For purposes of the DSR calculation, we are permitted to exclude from the Annual Debt Service Requirement principal and interest on debt if the debt is paid or to be paid from defeasance obligations which have been irrevocably deposited or set aside in trust for payment of such debt. Our failure to achieve the required DSR is not a default under the Master Indenture as long as a plan is timely adopted and being implemented and no payment default has occurred. However, subject to certain limited exceptions, we cannot issue additional secured obligations under the Master Indenture unless the DSR for the prior fiscal year (or period of prior 12 consecutive months) is at least 1.10 and the estimated DSR for the current and next two years (or, if applicable, two years following the anticipated commercial operation date of the assets being financed) is at least 1.10. Our DSR for the twelve months ended December 31, 2017 was 1.17. See Appendix A – Calculation of Financial Ratios.

Our Master Indenture also requires us to maintain an ECR at the end of each fiscal year of at least 18 percent. Our ECR equals our equity divided by the sum of our debt plus equity. Equity primarily consists of our aggregate net margins that we have not distributed in cash to our Members. Debt includes our indebtedness for borrowed money and capitalized leases but excludes indebtedness for which defeasance obligations (i.e., non-callable obligations of the United States) have been irrevocably deposited in trust. Our failure to maintain the ECR at the end of any given fiscal year would result in an event of default under the Master Indenture and restrict our ability to issue additional secured obligations under the Master Indenture. As of December 31, 2017, our ECR was 25.6 percent. See Appendix A – Calculation of Financial Ratios.

Pursuant to the Master Indenture, DSR and ECR are calculated based on unconsolidated Tri-State financials. Therefore, the details of the calculations are shown in Appendix A–Calculation of Financial Ratios.

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operation includes only the current portion.

Results of Operations

General

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

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

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

Year ended December 31, 2017 compared to year ended December 31, 2016

Operating Revenues

Member electric sales increased 159,274 MWhs to 15,905,656 MWhs in 2017 compared to 15,746,382 MWhs in 2016. MWhs sold increased due to an increase in sales to Members, partially offset by the withdrawal of KCEC in June 2016. We sold 144,324 MWhs to KCEC in 2016. Member electric sales revenue increased $65.2 million, or 5.7 percent, to $1.200 billion in 2017 compared to $1.135 billion in 2016. The increase in Member electric sales revenue was primarily due to the A-40 rate schedule effective January 1, 2017 and the net increase in MWhs sold. See "- Factors Affecting Results – Rates and Regulation" for a description of our rates to our Members.

Non-member electric sales decreased 45,048 MWhs to 2,113,011 MWhs in 2017 compared to 2,158,059 MWhs in 2016. Non-member electric sales revenue decreased $20.4 million, or 17.1 percent, to $98.9 million in 2017 compared to $119.3 million in 2016. Including the non-member electric sales revenue deferral of fourth quarter 2017 of $9.5 million, we recognized $5.5 million, net, of previously deferred non-member electric sales revenue in 2017 and $9.2 million of previously deferred non-member electric sales revenue in 2016. Excluding the effect of the previously deferred non-member electric sales revenue recognition in 2017 and 2016, non-member electric sales revenue decreased $16.7 million, or 15.2 percent, to $93.4 million in 2017 compared to $110.1 million in 2016. The decrease in MWhs sold and non-member electric sales was primarily due to the expiration of a long-term power sales arrangement in March 2017, partially offset by an increase in short-term market sales at lower rates than those received under the expired long-term power sales arrangement.

Operating Expenses

Purchased power decreased 79,036 MWhs to 7,249,540 MWhs in 2017 compared to 7,328,576 MWhs in 2016. The decrease in MWhs sold was due to a decrease in short-term market purchases of 328,591 MWhs, partially offset by an increase in long-term renewable energy power purchases of 194,336 MWhs and long-term firm purchases of 55,219 MWhs. Although MWhs sold decreased, purchased power expense increased $11.4 million to $339.8 million in 2017 compared to $328.4 million in 2016. The increase in purchased power expense was primarily due to an increase of $11.2 million, or 24.8 percent, to $56.3 million in 2017 compared to $45.1 million in 2016 for relatively similar MWh purchases from a new wind generating facility. Our purchases of power from the new wind generating facilities had a higher average cost per MWh for the first six months of 2017 compared to the same period in 2016 when we were paying a lower pre-commercial rate. Additionally, purchased power expense from Basin increased in 2017 compared to 2016 for relatively similar MWh purchases from Basin. Our purchases of power from Basin had a higher average cost per MWh in 2017 compared 2016 due to Basin's rate increase in the third quarter 2016. The increase in purchase power expense was partially offset by a decrease in short-term market purchases.

Depreciation, amortization and depletion expense increased $0.5 million to $174.5 million in 2017 compared to $174.0 million in 2016. Depreciation expense for generation plant increased $9.9 million primarily due to the shortened life associated with the anticipated December 31, 2022 retirement date of the Nucla Generating Station of $8.8 million and due to the shortened life associated with the anticipated December 31, 2025 retirement date of the Craig Station

Unit 1 of $2.9 million. Depreciation expense for transmission assets decreased $6.1 million primarily due to a $8.9 million decrease as a result of the transmission rate study, offset by additions of equipment throughout our transmission system. Depreciation expense for general plant and other decreased $3.3 million primarily due to a $5.3 million decrease as a result of the general plant rate study, offset by additions of equipment to our general plant.

Other Income

Other income decreased $2.0 million, or 7.1 percent, to $26.6 million in 2017 compared to $28.6 million in 2016. The decrease in other income was primarily due to the patronage allocation from Basin of $7.1 million in 2017 compared to $14.4 million for the same period in 2016. The decrease was partially offset by the recognition of $5.0 million of deferred membership withdrawal income in 2017.

Year ended December 31, 2016 compared to year ended December 31, 2015

Operating Revenues

Member electric sales decreased 34,288 MWhs to 15,746,382 MWhs in 2016 compared to 15,780,670 MWhs in 2015. The withdrawal of KCEC in June 2016 resulted in a 138,650 MWhs decrease in 2016 compared to 2015. Although MWhs sold decreased in 2016, Member electric sales revenue increased $9.0 million to $1.135 billion in 2016 compared to $1.126 billion in 2015 as a result of the new rate design implemented for 2016. See "- Factors Affecting Results – Rates and Regulation" for a description of our rates to our Members.

Non-member electric sales increased 131,534 MWhs, or 6.5 percent, to 2,158,059 MWhs in 2016 compared to 2,026,525 MWhs in 2015. The increase in MWhs sold was primarily due to 599,045 MWhs in the short-term market, offset by a decrease in firm sales of 467,511 MWhs due to the expiration of several long-term power sales arrangements in March 2016 and December 2015. Although non-member electric sales increased, non-member electric sales revenue decreased $0.9 million to $119.3 million in 2016 compared to $120.2 million in 2015. The decrease in non-member electric sales revenue was due to a decrease in firm sales of $17.1 million primarily due to the expiration of several long-term power sales arrangements in March 2016 and December 2015. The decrease in non-member electric sales was partially offset by the income recognition of $9.2 million of previously deferred non-member electric sales revenue. This recognition in 2016 was required by our Board in accordance with its budgetary and rate-setting authority. In addition, non-member electric short-term market sales increased $7.0 million due to the increase in MWhs sold.

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 Station. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is from our membership in the SPP, a regional transmission organization. The lease revenue is primarily from certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to others the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project. Other revenue decreased $2.5 million to $87.0 million in 2016 compared to $89.5 million in 2015. The decrease in other operating revenue was primarily due to a decrease in lease revenue of $12.6 million due to the expiration of power sales arrangements at our Knutson and Limon Generating Stations. This decrease was partially offset by a $7.9 million increase in transmission revenue resulting from our membership in the SPP and a $1.1 million increase in wheeling revenue.

Operating Expenses

Purchased power increased 397,365 MWhs, or 5.7 percent, to 7,328,576 MWhs in 2016 compared to 6,931,211 MWhs in 2015. Purchased power expense increased $23.4 million, or 7.7 percent, to $328.4 million in 2016 compared to $305.0 million in 2015. The increase in MWhs and purchased power expense was primarily due to higher renewable energy purchases resulting from two new facilities in 2016 with expense of $13.3 million, or 41.8 percent, to $45.1 million in 2017 compared to $31.8 million in 2016 and an increase in firm purchased power with expense of $15.9 million primarily due to a new power sales arrangement with PNM in June 2016. In addition, there was also a

6.6 percent increase in the average cost per MWh of purchased power (partially resulting from the August 2016 Basin rate increase).

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense increased $4.1 million to $235.6 million in 2016 compared to $231.5 million for the same period in 2015. The increase in expense was primarily due to lower coal expense in the second quarter of 2015 resulting from the one-time recognition of $24.4 million as a reduction to fuel expense because of the BNSF rate settlement. Excluding the effect of the BNSF rate settlement, fuel expense decreased $20.3 million to $235.6 million in 2016 compared to $255.9 million for the same period in 2015. The decrease was primarily due to reduced coal consumption due to a decrease in generation of 587,253 MWhs, or 4.9 percent in 2016 compared to 2015.

Production expense decreased $17.4 million, or 7.4 percent, to $218.0 million in 2016 compared to $235.4 million for the same period in 2015. The decrease in expense was primarily due to a decrease in maintenance outages in 2016 (generation maintenance expense was lower in 2016 than in 2015 due to scheduled generation maintenance expenses that occurred in 2015 at Craig Station and Laramie River Generating Station). This decrease was partially offset by a maintenance outage at Springerville Unit 3 during the fourth quarter of 2016.

Depreciation, amortization and depletion expense increased $21.3 million, or 13.9 percent, to $174.0 million in 2016 compared to $152.7 million for the same period in 2015. Depreciation expense increased in 2016 due to the shortened lives at three generating stations. San Juan Generating Station Unit 3 depreciation expense increased $3.2 million in 2016 compared to 2015 due to a shortened life associated with the anticipated December 31, 2017 retirement date of the unit. Beginning September 1, 2016, the Nucla Generating Station depreciation expense increased $2.8 million and Craig Station Unit 1 increased $0.8 million for 2016 due to the shortened lives associated with the anticipated retirement dates of December 31, 2022 and December 31, 2025, respectively. The remaining increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations.

Other Income

Capital credits from cooperatives increased $11.1 million, or 120.7 percent, to $20.3 million in 2016 compared to $9.2 million for the same period in 2015. The increase was primarily due to a patronage allocation from Basin of $14.4 million in 2016 compared to $4.6 million for the same period in 2015.

Income Taxes

Income taxes were $(1.4) million in 2016 compared to $0 for the same period in 2015. This resulted from a $1.9 million alternative minimum tax credit in lieu of bonus depreciation, partially offset by the current alternative minimum tax expense of $0.5 million.

Financial Condition as of December 31, 2017 compared to December 31, 2016

Assets

Other plant consists of mine assets 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 the use in the production of paper). Other plant increased $49.0 million, or 20.9 percent, to $283.5 million as of December 31, 2017 compared to $234.5 million as of December 31, 2016. The increase was primarily due to capital expenditures for the development of the Collom mining pit at the Colowyo Mine.

Coal inventory decreased $17.1 million, or 26.7 percent, to $46.8 million as of December 31, 2017 compared to $63.9 million as of December 31, 2016. The decrease was primarily due to inventory reduction efforts at Craig Station.

Regulatory assets increased $58.9 million, or 14.9 percent, to $454.5 million as of December 31, 2017 compared to $395.6 million as of December 31, 2016. The increase was primarily due to the impairment loss deferral of $93.5 million for development costs for a new coal-fired generating unit or units at Holcomb Generating Station. This increase was partially offset by amortization of $21.3 million to depreciation, amortization and depletion expense for recovery from our Members in rates and a $13.3 million decrease in deferred income tax expense primarily due to a reduction in the corporate income tax rate from 35 percent to 21 percent effective January 1, 2018 as provided for in the Tax Cuts and Jobs Act enacted on December 22, 2017.

Other deferred charges decreased $100.9 million, or 72.4 percent, to $38.5 million as of December 31, 2017 compared to $139.4 million as of December 31, 2016. The decrease was primarily due to the impairment loss of $93.5 million for the development costs for the expansion of the Holcomb Generating Station. In June 2017, we determined that the costs for the expansion of the Holcomb Generating Station were impaired. The impairment loss was deferred in accordance with the account requirements related to regulated operations at the discretion of our Board, which has budgetary and rate-setting authority.

Equity and Liabilities

Patronage capital equity increased $41.7 million, or 4.3 percent to $1.003 billion as of December 31, 2017 compared to $961.4 million as of December 31, 2016. The increase was due to a margin attributable to us of $61.7 million partially offset by 2017 patronage capital retirements to our Members of $20.0 million.

Long-term debt decreased $19.4 million to $3.120 billion as of December 31, 2017 compared to $3.140 billion as of December 31, 2016 and current maturities of long-term debt decreased $29.9 million, or 27.7 percent, to $78.0 million as of December 31, 2017 compared to $107.9 million as of December 31, 2016. The total decrease of $49.3 million was primarily due to debt payments of $108.3 million (primarily $49.1 million for the First Mortgage Obligation, Series 2009C, $39.3 million for the Springerville certificates and $5.5 million for the City of Gallup Series 2015 pollution control revenue bonds) partially offset by debt proceeds of $60.0 million from the First Mortgage Obligations, Series 2017A which were issued in December 2017.

Short-term borrowings consist of our commercial paper program that provides an additional financing source for our short-term liquidity needs. Short-term borrowings increased $24.8 million, or 20.7 percent, to $144.7 million as of December 31, 2017 compared to $119.9 million as of December 31, 2016. The increase was due to net additional commercial paper issued between January 1, 2017 and December 31, 2017 to fund capital expenditures and working capital requirements.

Regulatory liabilities decreased $13.7 million, or 14.3 percent, to $81.8 million as of December 31, 2017 compared to $95.5 million as of December 31, 2016. The decrease was primarily due to the income recognition of $15.0 million of previously deferred non-member electric sales revenue and the income recognition of $5.0 million of previously deferred other income in connection with the June 30, 2016 withdrawal of KCEC from membership in us. Also, there was a decrease in the deferred unrealized gain related to the change in fair value of the interest rate swaps of $7.8 million. These decreases were partially offset by the deferral of the October 2017 interest rate swap settlement of $4.6 million and the deferral of fourth quarter 2017 non-member electric sales revenue of $9.5 million.

Deferred income tax liability decreased $13.3 million, or 43.6 percent, to $17.2 million as of December 31, 2017 compared to $30.5 million as of December 31, 2016. The decrease was primarily due to a reduction in the corporate income tax rate from 35 percent to 21 percent effective January 1, 2018 as provided for in the Tax Cuts and Jobs Act enacted on December 22, 2017.

Other deferred credits decreased $12.8 million, or 19.3 percent, to $53.4 million as of December 31, 2017 compared to $66.2 million as of December 31, 2016. The decrease was primarily due to the January 12, 2017 settlement of the $15.5 million refund from TEP, required by the FERC for transmission service agreements that was recorded in other deferred credits in 2016. We returned $7.75 million to TEP and recognized $7.75 million that we retained as a reduction in transmission expense on our consolidated statement of operations during the first quarter of 2017. This decrease was partially offset by the recognition of $5.2 million for funds placed in an irrevocable trust for our share of the San Juan mine reclamation liability.

Liquidity

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of debt. As of December 31, 2017, we had $143.7 million in cash and cash equivalents. Our committed credit arrangement as of December 31, 2017 is as follows (dollars in thousands):

	Authorized Amount	Available December 31, 2017
Revolving Credit Agreement	$ 750,000 (1)	$ 605,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) The portion of this facility that was unavailable at December 31, 2017 was $145 million which was dedicated to support outstanding commercial paper.

The Revolving Credit Agreement has aggregate commitments of $750 million which includes a swingline sublimit of $100 million, a letter of credit sublimit of $200 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $200 million of the letter of credit sublimit, and $355 million of the commercial paper back-up sublimit remained available as of December 31, 2017. As of December 31, 2017, we have $605 million in availability under the Revolving Credit Agreement.

The Revolving Credit Agreement is secured under our Master Indenture and has a term extending through July 26, 2019. We expect to renew or replace the Revolving Credit Agreement prior to its expiration. Funds advanced under the Revolving Credit Agreement bear interest either at a Eurodollar rate or a base rate, at our option. The Eurodollar rate is the LIBOR rate for the term of the advance plus a margin (currently 1.00%) based on our credit ratings. The base rate is the highest of (a) the federal funds rate plus 1⁄2 of 1.00%, (b) the Bank of America prime rate, and (c) the one-month LIBOR rate plus 1.00% and plus a margin (currently 0%) based on our credit ratings. We had no outstanding borrowings at December 31, 2017 and no outstanding borrowings at December 31, 2016.

Under our commercial paper program, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our Revolving Credit Agreement, which was $500 million at December 31, 2017, thereby providing 100 percent dedicated support for any commercial paper outstanding. We had $145 million of commercial paper outstanding (prior to netting discounts) at December 31, 2017.

At December 31, 2016, we had a letter of credit issued under the Revolving Credit Agreement for the Moffat County, CO pollution control revenue bonds in the principal amount of $46.8 million plus accrued interest supported by the Revolving Credit Agreement. On October 17, 2017, the letter of credit was terminated following conversion of the Moffat County, CO pollution control revenue bonds on October 2, 2017, to bear interest from a variable rate mode to a five-year term rate mode ending October 3, 2022 at a rate of 2 percent per annum. At December 31, 2017, there were no letters of credit issued under the Revolving Credit Agreement.

The Revolving Credit Agreement contains financial covenants, including DSR and ECR requirements, in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facility. We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the Revolving Credit Agreement.

Cash Flow

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

Year ended December 31, 2017 compared to year ended December 31, 2016

Operating activities. Net cash provided by operating activities was $240.4 million in 2017 compared to $250.8 million in 2016, a decrease of $10.4 million. The decrease in cash provided by operating activities in 2017 compared to 2016 was primarily due to receiving $37.0 million of net cash in 2016 related to the withdrawal of KCEC from membership in us, the return of $7.75 million to TEP for the January 12, 2017 settlement agreement related to the time value refund we received in 2016 from TEP, an increase in payments for purchased power of $15.2 million, and an increase of $5.4 million for amounts paid for the wheeling of our electricity over transmission facilities owned by other energy companies. These decreases were partially offset by an increase in cash collected from Member accounts receivable.

Investing activities. Net cash used in investing activities was $212.8 million in 2017 compared to $219.8 million in 2016, a decrease of $7.0 million. The decrease was primarily due to a reduction in generation and transmission improvements and system upgrades in 2017 compared to 2016. This decrease was partially offset by $47.3 million of capital expenditures for the development of the Collom mining pit at the Colowyo Mine.

Financing activities. Net cash used in financing activities was $44.6 million in 2017 compared to net cash used in financing activities of $18.3 million in 2016, an increase of $26.3 million. The increase in net cash used in financing activities in 2017 compared to 2016 was primarily due to lower net borrowings.

Year ended December 31, 2016 compared to year ended December 31, 2015

Operating activities. Net cash provided by operating activities was $250.8 million in 2016 compared to $182.8 million in 2015, an increase of $68.0 million. The increase in operating activities in 2016 compared to 2015 was primarily due to the receipt of $49.5 million of cash related to the withdrawal of KCEC from membership in us and a $15.5 million refund from TEP required by the FERC for transmission service agreements. These increases in cash provided by operating activities were partially offset by higher purchased power expense due to renewable energy purchases from two new facilities in 2016 and an increase in interest payments (primarily for the Series 2016A Bonds) in 2016 compared to 2015.

Investing activities. Net cash used in investing activities was $219.8 million in 2016 compared to $281.1 million in 2015, a decrease of $61.3 million. The decrease was primarily due to lower capital expenditures in 2016 compared to 2015 for generation and transmission improvements and system upgrades.

Financing activities. Net cash used in financing activities was $18.3 million in 2016 compared to net cash provided by financing activities of $111.8 million, a decrease of $130.1 million. The decrease in financing activities was primarily due to higher long-term debt payments in 2016 compared to 2015 partially offset by higher debt proceeds in 2016 compared to 2015 and issuances of commercial paper of $119.9 million. Financing activities in 2016 were comprised primarily of long-term debt payments of $424.0 million (primarily $333.0 million for the Revolving Credit Agreement, $37.0 million for the Springerville certificates, $27.1 million for the First Mortgage Obligation, Series 2009C, $10.0 million on CoBank Series 2006B, 2012C, and unsecured notes, $7.7 million for the Coal Contract Receivable Collateralized Bonds and $5.3 million on the City of Gallup Series 2005 pollution control revenue bonds) and patronage capital retirements of $19.5 million. The decrease in 2016 financing activities was partially offset by debt proceeds of $307.0 million (principally $248.0 million on the Series 2016A Bonds and $62.0 million from our Revolving Credit Agreement) and a net increase of $119.9 million related to our commercial paper to finance our short-term liquidity needs.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility costs, market factors and other items affecting our forecasts. In the years 2018 through 2022, we forecast that we may invest approximately $1.1 billion in new facilities and upgrades to our existing facilities. Our investment forecast for new facilities and upgrades to existing facilities by capital expenditure category is as follows (dollars in thousands):

	2018	2019	2020	2021	2022	Total
Generation	$ 67,308	$ 64,043	$ 48,520	$ 88,779	$ 75,237	$ 343,886
Environmental Compliance	19,016	16,450	12,057	9,330	3,064	59,917
Transmission	150,005	139,729	106,534	72,919	88,942	558,129
General Plant	14,717	16,241	14,317	16,005	19,371	80,650
Coal Mining	49,495	18,218	4,751	3,230	3,693	79,386
Total Capital Expenditures by Category	$ 300,540	$ 254,681	$ 186,178	$ 190,263	$ 190,306	$ 1,121,968

Our actual capital expenditures depend on a variety of factors, including Member load growth, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our service area and development of the Collom mining pit at the Colowyo Mine.

Outstanding Obligations

As of December 31, 2017, we had $3.3 billion in outstanding obligations, including $2.8 billion secured on a parity basis by our Master Indenture, $145.0 million in short-term borrowings, two unsecured loan agreements totaling $41.5 million and the Springerville certificates totaling $418.7 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease).

The Revolving Credit Agreement has aggregate commitments in the amount of $750 million. We had no outstanding borrowings at December 31, 2017 and no outstanding borrowings at December 31, 2016. As of December 31, 2017, we have $605 million in availability (including $355 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement.

Contractual Commitments

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our owned and leased generating and transmission facilities, the financing of our operations and other matters. The following table summarizes our long-term contractual obligations as of December 31, 2017 (dollars in thousands):

	Payments Due by Period				
Obligations	**Total**	**Less Than 1 Year**	**1 - 3 Years**	**4 - 5 Years**	**More Than 5 Years**
Long-term Indebtedness					
Principal	$ 3,198,290	$ 78,004	$ 181,942	$ 187,093	$ 2,751,251
Interest (1)	2,724,338	154,014	291,788	270,962	2,007,574
Operating Lease Obligations	11,886	5,855	6,031	—	—
Construction Obligations	49,837	48,554	1,283	—	—
Coal Purchase Obligations	358,992	106,908	188,451	60,979	2,654
Total	$ 6,343,343	$ 393,335	$ 669,495	$ 519,034	$ 4,761,479

(1) Includes interest expense related to approximately $252 million of variable rate long-term debt. Future variable rates are based on the LIBOR swap rate curve and the Municipal Market Advisors curve as of December 29, 2017.

We expect to fund these obligations with cash flows from operations, borrowings under our commercial paper program and the issuance of additional long-term indebtedness.

Indebtedness. As of December 31, 2017, we had approximately $2.8 billion of debt outstanding secured on a parity basis under our Master Indenture. Our debt secured by the lien of our Master Indenture includes notes payable to CFC and CoBank (with the exception of one unsecured note), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, Series 2016A Bonds, First Mortgage Obligations, Series 2017A, pollution control revenue bonds, and amounts outstanding, if any, under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under our Master Indenture. As of December 31, 2017, we had two unsecured notes totaling $41.5 million and the Springerville certificates totaling $418.7 million. The Springerville certificates are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease.

On October 2, 2017, we converted our Moffat County, CO pollution control revenue bonds from a weekly variable rate mode to a five-year term rate mode at a rate of 2.0 percent ending October 3, 2022. On October 17, 2017, the letter of credit issued under the Revolving Credit Agreement to support the variable rate demand bonds was terminated.

On November 16, 2017, we entered into a Note Purchase Agreement with a group of institutional investors to sell our First Mortgage Obligations, Series 2017A in an aggregate principal amount of $120 million, consisting of $60 million of our 3.34% First Mortgage Obligations, Series 2017A Notes, Tranche 1, due December 12, 2029 and $60 million of our 3.39% First Mortgage Obligations, Series 2017A Notes, Tranche 2, due December 12, 2029 in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended. The closing of the sale of the Series 2017A Notes, Tranche 1 occurred on December 12, 2017 and the closing of the sale of the Series 2017A Notes, Tranche 2 is expected to occur on April 12, 2018, subject to the satisfaction of certain conditions.

Operating Lease Obligations. We have a 10-year power purchase agreement with AltaGas Brush Energy, Inc. to toll natural gas at the Brush Generating Station for 70 MWs which ends on December 31, 2019. We account for this power purchase agreement as an operating lease because it conveys to us the right to use power generating equipment for a stated period of time.

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

Coal Purchase Obligations. We have commitments to purchase coal for our generating stations under long-term contracts that expire between 2019 and 2034. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “A (stable outlook)” by S&P, and “A (stable outlook)” by Fitch. Our current short-term ratings are “P-2” by Moody’s, “A-1” by S&P, and “F1” by Fitch.

The Revolving Credit Agreement includes a pricing grid related to the LIBOR spread, commitment fee and letter of credit fees due under the facility. A downgrade of our senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include power sales arrangements that are required to be accounted for as operating leases, natural gas supply contracts, coal purchase contracts, and financial risk management contracts. Some of the contracts are directly tied to our credit rating generally being maintained at or above investment grade by S&P and Moody’s. We may enter into additional contracts which may contain similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

Off Balance Sheet Arrangements—Purchase Power Agreements Accounted for as Leases

We have a 10-year purchase power agreement with AltaGas Brush Energy, Inc. to toll natural gas at the Brush Generating Station for 70 MWs which ends on December 31, 2019. We account for this power purchase agreement as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Fair Value of Debt

The fair values of debt were estimated using discounted cash flow analyses based on our current incremental borrowings rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs). The carrying amounts and fair values of our debt as of December 31, 2017 and 2016 are as follows:

	2017		2016	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,211,421	$ 3,600,650	$ 3,259,721	$ 3,543,640

Commodity Price Risk

We have exposure to the market price of energy to meet obligations. We engage in structured hedging activities for both gas and electricity to mitigate exposure to market price volatility.

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

We have approximately 440 MWs of turbine capacity that is capable of operation on either natural gas or distillate fuel oil, providing fuel switching capability if needed. Further, we utilize approximately 110 MWs of our oil-only turbine capacity, 231 MWs of our gas-only combined-cycle capacity, and 70 MWs of gas-only tolling agreements, which affords substantial flexibility in meeting our obligations. Although we enjoy many benefits associated with these turbines and their capacity, we primarily utilize them as a peaking resource. For instance, in 2017, these resources provided approximately 1.8 percent of our energy available for sale.

Risk Management

We have implemented risk management programs which address both enterprise and energy commodity risks. These programs oversee all the risk functions and address commodity price volatility, counterparty exposure, credit risk, trading controls and hedging strategies. A corporate committee, consisting of senior executives and support staff, meets to assess market behavior, hedging activities and other corporate risks. Our Board is given briefings on risk management activities. Additionally, pursuant to Board policy, the Finance and Audit Committee and the Chief Executive Officer annually determine whether an external independent assessment of our risk management programs shall be performed.

Interest Rate Risk

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

As of December 31, 2017, we were exposed to the risk of changes in interest rates related to our $350.0 million of variable rate debt, including $145.0 million of short-term borrowings, $102.8 million of variable rate CFC notes and $102.2 million of variable rate CoBank notes. As of December 31, 2017, the weighted average interest rate on this variable rate debt was 2.24 percent.

Our objective in managing interest rate risk is to maintain a balance of fixed and variable rate debt that will lower our overall borrowing costs within reasonable risk parameters. As of December 31, 2017, we had 10.4 percent of our total debt in a variable rate mode. An increase in interest rates of 100 basis points would increase our annual debt service by approximately $3.5 million.

In addition to interest rate risk on existing variable rate debt, we are exposed to the risk of rising interest rates on any new long-term debt we may incur in connection with anticipated capital expenditures for new facilities and upgrades to our existing facilities. To mitigate the risk of rising interest rates, we entered into interest rate swaps to hedge a portion of our long-term debt interest rate exposure. On October 12, 2017, we settled one $90 million notional interest rate swap entered into in April 2016, which resulted in a realized gain of $4.6 million that has been deferred as a regulatory liability and is being amortized to interest expense over a 12-year term of the First Mortgage Obligations, Series 2017A. At December 31, 2017, the fair value of the remaining interest rate swap was an unrealized gain of $4.3 million, which was deferred in accordance with our regulatory accounting. The terms of the remaining interest rate swap contract are as follows (in thousands):

	Notional Amount	Fixed Rate (Pay)	Benchmark Interest Rate (Receive)	Effective Date	Maturity Date
Interest rate swap - June 2016	$ 80,000	2.304 %	30 year - LIBOR	June 2019	June 2049

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

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, 2017 and 2016, the related consolidated statements of operations, comprehensive income, equity and cash flows for each of the three years in the period ended December 31 2017, 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, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with U.S. generally accepted accounting principles.

Adoption of ASU No. 2016-18

As discussed in Note 2 to the consolidated financial statements, the Association changed its presentation of restricted cash in the consolidated statements of cash flows in 2016 and 2015 due to the adoption of ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*.

Basis for Opinion

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

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

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

/s/ Ernst & Young LLP

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

Denver, Colorado
March 9, 2018

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

As of December 31,	2017	2016
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,802,844	$ 5,682,613
Construction work in progress	175,567	212,081
Total electric plant	5,978,411	5,894,694
Less allowances for depreciation and amortization	(2,409,020)	(2,361,555)
Net electric plant	3,569,391	3,533,139
Other plant	283,546	234,457
Less allowances for depreciation, amortization and depletion	(105,660)	(89,809)
Net other plant	177,886	144,648
Total property, plant and equipment	3,747,277	3,677,787
Other assets and investments		
Investments in other associations	143,608	139,350
Investments in and advances to coal mines	18,274	18,176
Restricted cash and investments	5,979	1,000
Intangible assets, net of accumulated amortization	10,986	18,310
Other noncurrent assets	9,604	11,542
Total other assets and investments	188,451	188,378
Current assets		
Cash and cash equivalents	143,694	165,893
Restricted cash and investments	1,292	997
Deposits and advances	27,881	25,141
Accounts receivable—Members	102,035	97,925
Other accounts receivable	16,034	24,837
Coal inventory	46,849	63,945
Materials and supplies	89,459	87,768
Total current assets	427,244	466,506
Deferred charges		
Regulatory assets	454,523	395,615
Prepayment—NRECA Retirement Security Plan	37,607	43,627
Other	38,492	139,378
Total deferred charges	530,622	578,620
Total assets	**$ 4,893,594**	**$ 4,911,291**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 1,003,020	$ 961,364
Accumulated other comprehensive income (loss)	(210)	(286)
Noncontrolling interest	111,295	109,147
Total equity	1,114,105	1,070,225
Long-term debt	3,120,286	3,139,705
Total capitalization	4,234,391	4,209,930
Current liabilities		
Member advances	8,447	11,363
Accounts payable	117,510	105,511
Short-term borrowings	144,667	119,901
Accrued expenses	32,484	32,719
Current asset retirement obligations	3,087	6,237
Accrued interest	32,852	34,166
Accrued property taxes	27,137	27,584
Current maturities of long-term debt	78,004	107,903
Total current liabilities	444,188	445,384
Deferred credits and other liabilities		
Regulatory liabilities	81,824	95,512
Deferred income tax liability	17,205	30,517
Intangible liabilities	—	3,263
Asset retirement obligations	53,768	52,346
Other	53,396	66,164
Total deferred credits and other liabilities	206,193	247,802
Accumulated postretirement benefit and postemployment obligations	8,822	8,175
Total equity and liabilities	**$ 4,893,594**	**$ 4,911,291**

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,	2017	2016	2015
Operating revenues			
Member electric sales	$ 1,199,940	$ 1,134,781	$ 1,125,699
Non-member electric sales	98,872	119,326	120,234
Other	89,781	86,989	89,515
	1,388,593	1,341,096	1,335,448
Operating expenses			
Purchased power	339,830	328,407	305,045
Fuel	244,328	235,645	231,537
Production	207,993	218,008	235,398
Transmission	153,510	156,713	153,443
General and administrative	28,704	26,320	24,708
Depreciation, amortization and depletion	174,526	173,969	152,718
Coal mining	40,034	36,929	36,130
Other	15,971	18,099	18,500
	1,204,896	1,194,090	1,157,479
Operating margins	**183,697**	**147,006**	**177,969**
Other income			
Interest	4,723	4,368	4,355
Capital credits from cooperatives	12,934	20,349	9,189
Membership withdrawal	5,000	—	—
Other	3,966	3,934	3,981
	26,623	28,651	17,525
Interest expense, net of amounts capitalized	147,608	144,877	142,570
Income tax benefit	(1,092)	(1,417)	—
Net margins including noncontrolling interest	63,804	32,197	52,924
Net (income) loss attributable to noncontrolling interest	(2,148)	(449)	489
Net margins attributable to the Association	**$ 61,656**	**$ 31,748**	**$ 53,413**

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,	2017	2016	2015
Net margins including noncontrolling interest	$ 63,804	$ 32,197	$ 52,924
Other comprehensive income (loss):			
Unrealized gain (loss) on securities available for sale	43	(13)	(125)
Unrecognized actuarial gain (loss) on postretirement benefit obligation	106	(821)	1,528
Amortization of actuarial (gain) loss on postretirement benefit obligation included in net income	(73)	(41)	14
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	76	(875)	1,417
Comprehensive income including noncontrolling interest	63,880	31,322	54,341
Net comprehensive (income) loss attributable to noncontrolling interest	(2,148)	(449)	489
Comprehensive income attributable to the Association	**$ 61,732**	**$ 30,873**	**$ 54,830**

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,	2017	2016	2015
Patronage capital equity at beginning of year	$ 961,364	$ 952,082	$ 908,669
Net margins attributable to the Association	61,656	31,748	53,413
Retirement of patronage capital	(20,000)	(22,466)	(10,000)
Patronage capital equity at end of year	**1,003,020**	**961,364**	**952,082**
Accumulated other comprehensive income (loss) at beginning of year	(286)	589	(828)
Unrealized gain (loss) on securities available for sale	43	(13)	(125)
Unrecognized actuarial gain (loss) on postretirement benefit obligation	106	(821)	1,528
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(73)	(41)	14
Accumulated other comprehensive income (loss) at end of year	**(210)**	**(286)**	**589**
Noncontrolling interest at beginning of year	109,147	108,757	109,302
Net comprehensive income (loss) attributable to noncontrolling interest	2,148	449	(489)
Equity distribution to noncontrolling interest	—	(59)	(56)
Noncontrolling interest at end of year	**111,295**	**109,147**	**108,757**
Total equity at end of year	**$ 1,114,105**	**$ 1,070,225**	**$ 1,061,428**

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,	2017	2016	2015
Operating activities			
Net margins including noncontrolling interest	$ 63,804	$ 32,197	$ 52,924
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	174,526	173,969	152,718
Amortization of intangible asset	7,324	7,324	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,372	5,372	5,520
Amortization of debt issuance costs	1,985	1,931	1,870
Impairment loss - Holcomb expansion	93,494	—	—
Deferred Holcomb expansion impairment loss	(93,494)	—	—
Deferred membership withdrawal income	—	47,572	—
Recognition of deferred membership withdrawal income	(5,000)	—	—
Deferred revenue	9,527	—	—
Recognition of deferred revenue	(15,000)	(9,200)	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(4,417)	(17,933)	(7,179)
Proceeds from settlement of interest rate swap	4,625	—	—
Changes in operating assets and liabilities:			
Accounts receivable	4,924	(2,417)	10,936
Coal inventory	17,097	(4,668)	(18,604)
Materials and supplies	(1,691)	(2,267)	(5,432)
Accounts payable and accrued expenses	628	3,676	(12,188)
Accrued interest	(1,313)	(166)	1,814
Accrued property taxes	(448)	189	1,385
Other deferred credits - TEP transmission (settlement) refund	(15,521)	15,521	—
Other deferred credits - BNSF settlement	—	—	(29,381)
Other	(6,039)	(288)	21,065
Net cash provided by operating activities	**240,383**	**250,812**	**182,772**
Investing activities			
Purchases of plant	(214,781)	(219,771)	(290,428)
Changes in deferred charges	1,112	(298)	9,031
Proceeds from other investments	911	313	321
Net cash used in investing activities	**(212,758)**	**(219,756)**	**(281,076)**
Financing activities			
Changes in Member advances	(6,852)	(887)	(7,041)
Payments of long-term debt	(108,301)	(423,957)	(113,063)
Proceeds from issuance of debt	60,000	307,000	240,183
Increase in short-term borrowings, net	24,767	119,901	—
Retirement of patronage capital	(12,815)	(19,486)	(8,286)
Other	(1,349)	(854)	—
Net cash provided by (used in) financing activities	**(44,550)**	**(18,283)**	**111,793**
Net increase (decrease) in cash, cash equivalents and restricted cash and investments	**(16,925)**	**12,773**	**13,489**
Cash, cash equivalents and restricted cash and investments – beginning	**167,890**	**155,117**	**141,628**
Cash, cash equivalents and restricted cash and investments – ending	**$ 150,965**	**$ 167,890**	**$ 155,117**
Supplemental cash flow information:			
Cash paid for interest	$ 159,112	$ 158,978	$ 154,657
Cash paid for income taxes	$ —	$ 1,100	$ —
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ (3,242)	$ (1,354)	$ 2,173
Renewal of transmission right of way easements	$ —	$ —	$ 27,447

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 organized for the purpose of providing electricity to our member distribution systems ("Member(s)"), that serve large portions of Colorado, Nebraska, New Mexico and Wyoming. 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 2017, 2016 and 2015, total megawatt-hours sold were 18.0, 17.9 and 17.8 million, respectively, of which 88.3, 88.0 and 88.6 percent, respectively, were sold to Members. Total revenue from electric sales was $1.3 billion for 2017 and 2016 and $1.2 billion for 2015 of which 92.3, 90.5, and 90.3 percent in 2017, 2016 and 2015, respectively, was from Member sales. Energy resources were provided by our generation and purchased power, of which 61.4, 60.8 and 63.3 percent in 2017, 2016 and 2015, respectively, were from our generation.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constitute approximately 96.8 percent of our revenue from Member sales for 2017) and extending through 2040 for the remaining Member (Delta-Montrose Electric Association). These contracts are subject to automatic extension thereafter until either party provides at least two years' notice of its intent to terminate. Each contract obligates us to sell and deliver to the Member and obligates the Member to purchase and receive at least 95 percent of its electric power requirements from us. Each Member may elect to provide up to 5 percent of its requirements from distributed or renewable generation owned or controlled by the Member. As of December 31, 2017, 22 Members have enrolled in this program with capacity totaling approximately 143 megawatts of which 98 megawatts are in operation.

Revenue from one Member, United Power, Inc., was $168.8 million, or 14.1 percent, of our Member revenue and 12.1 percent of our total operating revenues in 2017. No other Member exceeded 10 percent of our Member revenue or our total operating revenues in 2017.

Power is provided to Members at rates determined by the Board of Directors ("Board"). Rates are designed to recover all costs and provide margins to increase 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 Members through the utilization of a portfolio of resources, including generating 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 generating facilities, we have direct ownership and investment in coal mines.

We, including our subsidiaries, employ 1,546 people, of which 319 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: Our consolidated financial statements include the accounts of the Association, our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 12—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 three 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), the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")) and the San Juan Project (operated by Public Service Company of New Mexico). Our ownership in the San Juan Project terminated December 31, 2017. 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 Members and do so through the utilization of a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and short-term energy purchases. In support of our coal generating resources, we have 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.

BUSINESS COMBINATIONS: We account for business acquisitions by applying the accounting standard related to business combinations. In accordance with this method, the identifiable assets acquired, the liabilities assumed and any noncontrolling interests in the acquired entities are required to be recognized at their acquisition date fair values. We typically engage an independent valuation firm to determine the acquisition date fair values of most of the acquired assets and assumed liabilities. The excess of total consideration transferred over the net assets acquired is recognized as goodwill. Acquisition-related costs such as legal fees, accounting services fees and valuation fees, are expensed as incurred. We are required to consolidate these acquired entities.

If an acquisition does not result in acquiring a business, the transaction is accounted for as an acquisition of assets. This method requires measurement and recognition of the acquired net assets based upon the amount of cash transferred and the amount paid for acquisition-related costs. There is no goodwill recognized in an acquisition of assets.

We adopted Accounting Standards Update ("ASU") 2017-01, *Business Combinations (Topic 805) – Clarifying the Definition of a Business* as of December 31, 2017, which changes the definition of a business to assist entities in evaluating whether a set of transferred assets and activities is deemed to be a business. Under this amendment, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. This amendment may result in more transactions being accounted for as asset acquisitions rather than business combinations. The adoption of this standard, which will be applied prospectively, had no impact on our consolidated financial statements.

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 June 2017, we determined that the $93.5 million of development costs (which excluded the costs of land and water rights) for a new coal-fired generating unit or units at Holcomb Generating Station were impaired. The impairment loss was deferred in accordance with the accounting requirements related to regulated operations at the discretion of our Board. See Note 2 – Accounting for Rate Regulation. There were no impairments of long-lived assets recognized for 2016 and 2015.

VARIABLE INTEREST ENTITIES: We evaluate our arrangements and relationships with other entities, including our investments in other associations and investments in coal mines, 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 in, 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 12—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, which has budgetary and rate-setting authority, if it is probable that these amounts will be refunded or recovered through future rates. Regulatory assets are costs we expect to recover from our Members based on rates approved by our Board in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets as expenses and regulatory liabilities as operating revenues, other income, or a reduction in expense concurrent with their recovery in rates.

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

	2017	2016
Regulatory assets		
Deferred income tax expense (1)	$ 17,205	$ 30,517
Deferred prepaid lease expense – Craig Unit 3 Lease (2)	3,237	9,710
Deferred prepaid lease expense – Springerville Unit 3 Lease (3)	88,296	90,587
Goodwill – J.M. Shafer (4)	54,843	57,692
Goodwill – Colowyo Coal (5)	39,261	40,294
Deferred debt prepayment transaction costs (6)	158,187	166,815
Deferred Holcomb expansion impairment loss (7)	93,494	—
Total regulatory assets	454,523	395,615
Regulatory liabilities		
Interest rate swap - unrealized gain (8)	4,311	12,140
Interest rate swap - realized gain (9)	4,614	—
Deferred revenues (10)	30,327	35,800
Membership withdrawal (11)	42,572	47,572
Total regulatory liabilities	81,824	95,512
Net regulatory asset	$ 372,699	$ 300,103

(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. See Note 8 – Income Taxes.

(2) Represents deferral of the loss on acquisition related to the Craig Generating Station ("Craig Station") Unit 3 prepaid lease expense upon acquisitions of equity interests in 2002 and 2006. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation, amortization and depletion expense in the amount of $6.5 million annually through December 31, 2017, and $3.2 million for the six month period ending June 30, 2018, and recovered from our Members in rates.

(3) 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 Members in rates.

(4) 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 Members in rates.

(5) 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 Members in rates.

(6) 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 average life of the new debt issued and recovered from our Members in rates.

(7) 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. On March 17, 2017, the Kansas Supreme Court issued a decision upholding the air permit for one unit at Holcomb Generating Station of 895 megawatts. The air permit expires if construction of the Holcomb expansion does not commence within 18 months. Although a final decision has not been made by our Board on whether to proceed with the construction of the Holcomb expansion, we have assessed the probability of us entering into construction for the Holcomb expansion as remote. Based on this assessment, we have determined that

the costs incurred for the Holcomb expansion are impaired and not recoverable. At the discretion of our Board, the impaired loss has been deferred as a regulatory asset and will be recovered from our Members in rates. The plan for the recovery has not been determined by our Board. Once the plan for recovery is determined, the deferred impairment loss will be recognized in other operating expenses.

(8) Represents deferral of an unrealized gain related to the change in fair value of a forward starting interest rate swap that was entered into in June 2016 in order to hedge interest rates on anticipated future borrowings. Upon settlement of this interest rate swap, the realized gain or loss will be deferred and subsequently recognized as interest expense when amortized over the term of the associated long-term debt borrowing. See Note 5 – Long-Term Debt and Note 7 – Fair Value.

(9) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap that was entered into in April 2016. 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. See Note 5 – Long-Term Debt.

(10) Represents deferral of the recognition of non-member electric sales revenue. $9.2 million of this deferred revenue was recognized in non-member electric sales revenue in 2016 and $15.0 million of this deferred revenue was recognized in non-member electric sales revenue during the six months ended June 30, 2017. $9.5 million of fourth quarter 2017 non-member electric sales revenue was deferred. The balance of deferred non-member electric sales revenues of $30.3 million at December 31, 2017 will be refunded to Members through reduced rates when recognized in non-member electric sales revenue in future periods.

(11) Represents deferral of the recognition of other income of $47.6 million recorded in connection with the June 30, 2016 withdrawal of Kit Carson Electric Cooperative, Inc. from membership in us. $5.0 million of this deferred membership withdrawal income was recognized in other income during the six months ended June 30, 2017. No deferred membership withdrawal income was recognized during the six month period ended December 30, 2017. The remaining deferred membership withdrawal income will be refunded to 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 of 4.7 percent were used for 2017 and 2016 and 4.4 percent was used for 2015. The amount of interest capitalized during construction was $11.0, $13.8 and $13.5 million during 2017, 2016 and 2015, 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: The accounting for lease transactions in conformity with GAAP requires management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life, in order to determine whether a lease should be classified as operating or capital.

We are the lessor under a power sale arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys the right to use our power generating equipment for a stated period of time. The lease revenue from this arrangement is included in other operating revenue on our consolidated statements of operations. We are the lessee under a power purchase arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time. It is included in other operating expenses on our consolidated statements of operations. See Note 9 - Leases.

INVESTMENTS IN OTHER ASSOCIATIONS: Investments in other associations include investments in the patronage capital of other cooperatives (accounted for using the cost method) and other required investments in the organizations. Under this method, 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):

	2017	2016
Basin Electric Power Cooperative	$ 101,820	$ 99,301
National Rural Utilities Cooperative Finance Corporation	27,317	26,933
CoBank, ACB	8,174	7,217
Western Fuels Association, Inc.	2,346	2,245
Other	3,951	3,654
Investments in other associations	$ 143,608	$ 139,350

INVESTMENTS IN AND ADVANCES TO COAL MINES: We have direct ownership and investments in coal mines to support our coal generating resources. We, and certain participants in the Yampa Project, are members 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. Our investment in Trapper Mining is recorded using the equity method. In addition, we have 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 MBPP, which is the operator of Laramie River Generating Station. 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):

	2017	2016
Investment in Trapper Mine	$ 14,998	$ 14,503
Advances to Dry Fork Mine	3,276	3,673
Investments in and advances to coal mines	$ 18,274	$ 18,176

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

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

We adopted ASU 2016-18, *Statement of Cash Flows (Topic 230) – Restricted Cash* as of December 31, 2017. This amendment requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows.

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):

	2017	2016
Cash and cash equivalents	$ 143,694	$ 165,893
Restricted cash and investments - current	1,292	997
Restricted cash and investments - noncurrent	5,979	1,000
Cash, cash equivalents and restricted cash and investments	$ 150,965	$ 167,890

ASU 2016-18 was adopted using a retrospective transition method which required each comparative period to reflect the application of the amendment in our consolidated statements of cash flows. The following consolidated statements of cash flows reporting lines for the year end December 31, 2016 were affected by the adoption of this amendment:

For the year ended December 31, 2016	As Adjusted	As Originally Reported	Effect of Change
Operating activities			
Adjustments to reconcile net margins to net cash provided by operating activities:			
Change in restricted cash and investments	$ —	$ (137)	$ 137
Other	$ (288)	$ (175)	$ (113)
Net cash provided by operating activities	**$ 250,812**	**$ 250,788**	**$ 24**
Financing activities			
Proceeds from investment in securities pledged as collateral	$ —	$ 7,426	$ (7,426)
Other	$ (854)	$ 277	$ (1,131)
Net cash used in financing activities	**$ (18,283)**	**$ (9,726)**	**$ (8,557)**
Net increase in cash, cash equivalents and restricted cash and investments	**$ 12,773**	**$ 21,306**	**$ (8,533)**
Cash, cash equivalents and restricted cash and investments – beginning	**$ 155,117**	**$ 144,587**	**$ 10,530**
Cash, cash equivalents and restricted cash and investments – ending	**$ 167,890**	**$ 165,893**	**$ 1,997**

The following consolidated statements of cash flows reporting lines for the year end December 31, 2015 were affected by the adoption of this amendment:

For the year ended December 31, 2015	**As Adjusted**	**As Originally Reported**	**Effect of Change**
Operating activities			
Adjustments to reconcile net margins to net cash provided by operating activities:			
Change in restricted cash and investments	$ —	$ 29,113	$ (29,113)
Other	$ 21,065	$ 21,324	$ (259)
Net cash provided by operating activities	**$ 182,772**	**$ 212,144**	**$ (29,372)**
Financing activities			
Proceeds from investment in securities pledged as collateral	$ —	$ 8,931	$ (8,931)
Other	$ —	$ 327	$ (327)
Net cash provided by financing activities	**$ 111,793**	**$ 121,051**	**$ (9,258)**
Net increase in cash, cash equivalents and restricted cash and investments	**$ 13,489**	**$ 52,119**	**$ (38,630)**
Cash, cash equivalents and restricted cash and investments – beginning	**$ 141,628**	**$ 92,468**	**$ 49,160**
Cash, cash equivalents and restricted cash and investments – ending	**$ 155,117**	**$ 144,587**	**$ 10,530**

The adoption of ASU 2016-18 had no impact on our consolidated statements of financial position and consolidated statements of operations.

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 classified as available-for-sale securities. At December 31, 2017, the cost and estimated fair value of the investments based upon their active market value (Level 1 inputs) were $1.0 and $1.2 million, respectively, with a net unrealized gain balance of $0.2 million. At December 31, 2016, the cost and estimated fair value of the investments were $1.0 and $1.1 million, respectively, with a net unrealized gain balance of $0.1 million. The estimated fair value of the investments is included in other noncurrent assets on our consolidated statements of financial position. The unrealized gains at December 31, 2017 and 2016 are reported as a component of accumulated other comprehensive income as of those dates. Changes in the net unrealized gains or losses are reported as a component of comprehensive income.

INVENTORIES: Coal inventories at our owned generating stations are stated at LIFO (last-in, first-out) cost and were $26.8 and $46.0 million as of December 31, 2017 and 2016, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2017, we realized lower coal fuel expense of $4.2 million as a result of a LIFO inventory liquidation at our generating stations.

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 Members in rates subject to approval by our Board, which has budgetary and rate-setting authority. Preliminary surveys and investigations were primarily comprised of development costs for the expansion at Holcomb Generating Station of

$91.3 million as of December 31, 2016. There was no balance for the expansion at Holcomb Generating Station as of December 31, 2017 as a result of our determination during the second quarter of 2017 that the costs incurred for the expansion at Holcomb Generating Station were impaired. The impairment loss was deferred at the discretion of our Board. See Note 2 – Accounting for Rate Regulation.

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, Yampa Project – Craig Generating Station Units 1 and 2, and San Juan Project – San Juan Unit 3. Our ownership in the San Juan Project terminated December 31, 2017. We also make advance payments to the operating agent of Springerville Unit 3.

During 2016, we entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate exposure. One of these interest rate swaps was settled in October 2017. The realized gain of $4.6 million related to the settlement of this interest rate swap was deferred as a regulatory liability in accordance with the accounting requirements related to regulated operations. This realized gain is being amortized to interest expense over the 12-year term of the associated private placement debt issuance. The unrealized gain of $4.3 and $12.1 million as of December 31, 2017 and 2016, respectively, on the outstanding interest rate swaps was deferred in accordance with the accounting requirements related to regulated operations. See Note 2 – Accounting for Rate Regulation.

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

	December 31, 2017	December 31, 2016
Preliminary surveys and investigations	$ 19,737	$ 111,592
Advances to operating agents of jointly owned facilities	10,740	11,871
Interest rate swaps	4,311	12,140
Other	3,704	3,775
Total other deferred charges	$ 38,492	$ 139,378

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 OBLIGATIONS: We account for current obligations associated with the future retirement of tangible long-lived assets 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. 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. These liabilities are included in asset retirement obligations.

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

Generation: We, including our undivided interest in jointly owned facilities, have asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the generating stations.

Transmission: We had an asset retirement obligation to remove a certain transmission line and related substation assets resulting from an agreement to relocate the line. The asset retirement obligation was settled during the third quarter of 2017.

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

	2017	2016
Asset retirement obligations at beginning of period	$ 58,583	$ 55,215
Liabilities incurred	4,294	5,844
Liabilities settled	(4,935)	(1,298)
Accretion expense	2,623	3,751
Change in cash flow estimate	(3,710)	(4,929)
Total Asset retirement obligations at end of period	$ 56,855	$ 58,583
Less current asset retirement obligations at end of period	(3,087)	(6,237)
Long-term asset retirement obligations at end of period	$ 53,768	$ 52,346

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.

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. $33.4 million will be paid by us for these easements from 2017 through the individual easement terms ending between 2036 and 2040. The present value for the easement payments were $21.3 and $20.6 million as of December 31, 2017 and December 31, 2016, respectively, which is recorded as other deferred credits and other liabilities.

We received $15.5 million in 2016 from Tucson Electric Power Company ("TEP") as ordered by the United States Federal Energy Regulatory Commission ("FERC"). In 2015, TEP filed various non-conforming point-to-point transmission services agreements with FERC, including transmission services agreements between TEP and us. FERC ordered TEP to make a time value refund to us with regard to these transmission services agreements. TEP appealed the FERC order and stated that the funds were subject to refund in the event TEP was ultimately successful in its appeal. In 2016, due to uncertainties regarding the ultimate outcome of this matter, we recorded the total receipt of $15.5 million in other deferred credits. On January 12, 2017, we entered into a settlement agreement with TEP and TEP moved to dismiss the appeal with prejudice. We returned $7.75 million to TEP and recognized $7.75 million that we retained as a reduction in transmission expense on our statement of operations during the first quarter of 2017.

We have received deposits from others for the use of optical fiber and these are reflected in unearned revenue until recognized 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, 2017	December 31, 2016
Transmission easements	$ 21,337	$ 20,562
TEP transmission refund	—	15,521
Unearned revenue	3,735	4,000
Customer deposits	2,898	3,338
Other	25,426	22,743
Total other deferred credits and other liabilities	$ 53,396	$ 66,164

MEMBERSHIPS: There are 43 $5 memberships outstanding at December 31, 2017 and 2016.

PATRONAGE CAPITAL: Our net margins are treated as advances of capital from our Members and are allocated to our Members on the basis of their electricity purchases from us. Net losses, should they occur, are not allocated to Members, but are offset by future margins. Margins not 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.

ACCOUNTS RECEIVABLE—MEMBERS AND OTHER: Receivables are primarily related to electric sales to Members and electric sales and other transactions with electric utilities. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible.

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. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is from our membership in the Southwest Power Pool, a regional transmission organization. The lease revenue is primarily from a power sales arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys to others the right to use power generating equipment for a stated period of time. See Note 9 – Leases. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract which ended December 31, 2017 to other joint owners in the Yampa Project (the "Yampa Participants"). The associated Colowyo Mine expenses are included in coal mining, depreciation, amortization, and depletion and interest 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. However, in accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current provision. See Note 8 – 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 $1.5 and $1.9 million at December 31, 2017 and 2016, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was $0.4 million, $0.3 million and $0.1 million in 2017, 2016 and 2015, respectively.

EVALUATION OF SUBSEQUENT EVENTS: We evaluated subsequent events through March 9, 2018, which is the date when the financial statements were issued.

NEW ACCOUNTING PRONOUNCEMENTS: In March 2017, the Financial Accounting Standards Board ("FASB") issued ASU 2017-07, *Compensation-Retirement Benefits (Topic 715)-Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. This amendment disaggregates the accounting for the service cost component of the net periodic benefit cost of an entity's defined benefit pension and other postretirement benefit plans from the other components of the net periodic benefit cost (such as interest expense, recognition of actuarial gain or loss on postretirement benefit obligations, and amortization of prior service cost or credit). The service cost component is to be included in the same income statement line item(s) as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be included separately from the line item(s) that include service cost and outside of any subtotal of operating income, if one is presented. ASU 2017-07 also limits the portion of net benefit cost that is eligible for capitalization to property, plant and equipment to the current service cost component. This amendment is effective for fiscal years beginning after December 31, 2017, including interim periods within those annual periods. The guidance is required to be applied using a full retrospective transition method. We do not expect this amendment to have a material impact on our consolidated statements of operations.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* This amendment requires a lessee to recognize substantially all leases (whether operating or finance leases) on the balance sheet as a right-of-use asset and an associated lease liability. This amendment includes an accounting policy election by class of underlying asset to exclude short-term leases. A short-term lease is defined as a lease that, at commencement date, has a lease term of 12 months or less and does not include an option to purchase the underlying asset that the lessee is reasonably certain to exercise. A right-of-use asset represents a lessee's right to use (control the use of) the underlying asset for the lease term. A lease liability represents a lessee's liability to make lease payments. The right-of-use asset and the lease liability are initially measured at the present value of the lease payments over the lease term. For finance leases, the lessee subsequently recognizes interest expense and amortization of the right-of-use asset, similar to accounting for capital leases under current GAAP. For operating leases, the lessee subsequently recognizes straight-line lease expense over the life of the lease. Lessor accounting remains substantially the same as that applied under current GAAP. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)-Land Easement Practical Expedient for Transition to Topic 842*. This amendment permits an entity to elect an optional transition practical expedient to not evaluate under Topic 842 land easements that exist or that expired before the entity's adoption of Topic 842. Once an entity adopts Topic 842, the new guidance should be applied prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. ASU 2016-02, as amended by subsequent ASUs, is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The guidance is to be applied using a modified retrospective transition method with the option to elect a package of practical expedients (specifically, expired or existing contracts assessed under Topic 840 need not be reassessed, lease classification for any expired or existing leases assessed under Topic 840 need not be reassessed, and an entity need not reassess initial direct costs for any existing leases). We are currently evaluating the impact of this amendment on our consolidated statements of financial position and consolidated statements of operations.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. This amendment requires an entity to measure investments in equity securities, except those that result in consolidation or are accounted for under the equity method of accounting, at fair value with changes in fair value recognized in net income. For equity investments that do not have readily determinable fair value and that don't qualify for the existing practical expedient in ASC 820, *Fair Value Measurements*, to estimate fair value using the net asset value per share of the investment, the amendment allows entities to measure those investments at cost, less any impairment, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investment of the same issuer. This amendment also affects financial liabilities using the fair value option and the presentation and disclosure requirements for financial instruments. Also, an entity should present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application by public business entities to financial statements of fiscal years or interim periods that have not yet been issued or, by all other entities, that have not yet been made available for issuance are permitted as of the beginning of the fiscal year of adoption. An entity should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments related to equity securities without readily determinable fair values (including disclosure requirements) should be applied prospectively to equity investments that exist as of the date of adoption of the update. We are currently evaluating the impact of this amendment on our consolidated statements of financial position and consolidated statements of operations.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* as amended by subsequent ASUs issued in 2015, 2016 and 2017. The core principle under the new revenue standard requires that revenue should be recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. To achieve the core principle, the following steps are required: (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This new standard also requires enhanced quantitative and qualitative disclosures to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Our evaluation process of this standard includes, but is not limited to, identifying contracts within the scope of Topic 606, reviewing the contracts, and documenting our analysis of these contracts. We have evaluated our wholesale electric service contracts with our 43 Members, which was $1.2 billion, or 86.4 percent, of our total operating revenues in 2017. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. Our Class A rate schedule for electric power sales to our Members consist of two billing components: an energy rate and demand rates. Our Members are billed on a monthly basis for energy consumed and demand during the period. We transfer control of the electricity over time and the Member simultaneously receives and consumes the benefits of the electricity. The amount we invoice Members on a monthly basis corresponds directly with the value to the Member of our performance. Accordingly, we do not believe there will be a material impact to our recognition of revenue from the sale of electricity to our Members.

We have evaluated the significant contracts for our non-member electric sales revenue. Our non-member electric sales revenue was $98.9 million, or 7.1 percent, of our total operating revenues in 2017. We do not believe there will be a material impact to our recognition of revenue from the sale of electricity to non-members.

We have also evaluated the impact of this new standard on our other operating revenues. Our other operating revenues were $89.8 million in 2017, or 6.5 percent, of our total operating revenues and primarily consisted of coal sales to third-parties, transmission revenue, wheeling revenue, and rent revenue from an operating lease arrangement. We do not believe there will be a material impact to our recognition of revenue from other operating revenues.

The new standard is effective for the fiscal year beginning January 1, 2018 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach where prior year results are not restated; however a cumulative-effect adjustment would be recognized in patronage capital equity at the date of adoption (January 1, 2018). We will adopt the standard using the modified retrospective transition method. While the adoption of this standard, including the cumulative-effect adjustment, is not expected to have a material impact on our consolidated financial statements, we anticipate expanded revenue disclosures related to the nature, timing, and uncertainty in revenues. We continue to evaluate the impacts of outstanding industry-related issues being addressed by the American Institute of CPAs' Revenue Recognition Working Group and the FASB's Transition Resource Group.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial statements to conform to the 2017 presentation.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

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

ELECTRIC PLANT: 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			December 31, 2017	December 31, 2016
Generation plant	0.89 %	to	6.27 %	$ 3,558,369	$ 3,542,578
Transmission plant	1.11 %	to	2.09 %	1,496,362	1,407,846
General plant	1.46 %	to	9.53 %	484,022	461,148
Other	2.75 %	to	10.00 %	264,091	271,041
Electric plant in service (at cost)				5,802,844	5,682,613
Construction work in progress				175,567	212,081
Less allowances for depreciation and amortization				(2,409,020)	(2,361,555)
Electric plant				$ 3,569,391	$ 3,533,139

At December 31, 2017, we had $49.8 million of commitments to complete construction projects, of which approximately $48.5, $0.8 and $0.5 million are expected to be incurred in 2018, 2019 and 2020, respectively.

On September 1, 2016, we announced that the owners of Craig Station Unit 1 reached an agreement with the Colorado Department of Public Health and Environment, U.S. Environmental Protection Agency, WildEarth Guardians and the National Parks Conservation Association to revise the Colorado Visibility and Regional Haze State Implementation Plan (“SIP”). Under the proposed revision to the SIP, the owners of Craig Station Unit 1 intend to retire Craig Station Unit 1 by December 31, 2025. The retirement date was previously estimated to be December 31, 2051. We are the operator of Craig Station and own 24 percent of Craig Station Unit 1. Craig Station Unit 2 and Unit 3 will continue to operate. Our share of Craig Station Unit 1 is 102 megawatts with a net book value of $26.9 million as of December 31, 2017. The shortened life increased annual depreciation expense in the amount of $2.9 million.

As part of the above mentioned agreement on proposed revisions to the SIP, we intend to retire the Nucla Generating Station by December 31, 2022. The retirement date was previously estimated to be December 31, 2049. We are the operator and sole owner of Nucla Generating Station with a net book value of $55.2 million as of December 31, 2017. The shortened life increased annual depreciation expense in the amount of $8.8 million.

Effective January 1, 2017, we adopted depreciation rates that reflect rates determined in a depreciation rate study for our transmission plant and most of our general plant, which decreased depreciation expense $14.2 million. A depreciation rate study was completed during 2017 for our generation plant and these rates were adopted beginning on July 1, 2017, which increased depreciation expense $0.7 million.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2017 (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 %	$ 396,395	$ 237,467	$ 4,792
MBPP - Laramie River Station	24.13 %	415,071	299,753	25,917
San Juan Project – San Juan Unit 3 (1)	8.20 %	—	—	—
Total		$ 811,466	$ 537,220	$ 30,709

(1) Our ownership in the San Juan Project terminated December 31, 2017.

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 the 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, which supplies coal to the Nucla Generating Station. New Horizon Mine has ceased coal production and on June 8, 2017 started final reclamation. Elk Ridge also owns Colowyo Coal, which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. We are currently mining the South Taylor pit and started development on the Collom mining pit in 2017. During 2017, we incurred capital expenditures of $46.8 million related to the Collom mining pit development. We also own a 50 percent undivided ownership in the land and the rights to mine the property known as Fort Union Mine. 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, 2017	December 31, 2016
Colowyo Mine assets	$ 223,377	$ 173,626
New Horizon Mine assets	46,946	47,404
Fort Union Mine assets	846	1,158
Accumulated depreciation and depletion	(99,100)	(83,595)
Net mine assets	172,069	138,593
Non-utility assets	12,377	12,269
Accumulated depreciation	(6,560)	(6,214)
Net non-utility assets	5,817	6,055
Net other plant	$ 177,886	$ 144,648

NOTE 4 – INTANGIBLES

INTANGIBLE ASSETS: The December 2011 acquisition of TCP resulted in recording an intangible asset in the amount of $55.5 million relating to a contractual obligation that TCP has to a third party under a purchase power agreement. The $55.5 million intangible asset represented the amount that the purchase power agreement contract terms were above market value at the acquisition date and is being amortized on a straight-line basis over the remaining life of the purchase power agreement through June 30, 2019. The straight-line method is consistent with the terms of the purchase power agreement as this contract is for a fixed amount of capacity at a fixed capacity rate that stays constant over the term of the contract. The amortization of the purchase power agreement intangible asset is accounted for as a reduction of the revenue generated by the purchase power agreement and is included in other operating revenue. The amortization was $7.3 million in each of the years 2017, 2016 and 2015 and will be recognized over each of the next two years as follows (dollars in thousands):

2018	$ 7,324
2019	3,662
	$ 10,986

INTANGIBLE LIABILITIES: The December 2011 acquisition of Colowyo Coal resulted in recording an intangible liability of $18.0 million relating to a contractual obligation that Colowyo Coal had to sell coal to the Yampa Participants through 2017. The $18.0 million intangible liability represented the amount that the coal sale contract terms were below market at the acquisition date and was amortized based upon the contracted tonnage with the Yampa Participants over the life of the coal contract ending December 31, 2017. Therefore, there was no remaining intangible liability balance as of December 31, 2017. There was a $3.3 million balance as of December 31, 2016, which is included in intangible liabilities on our consolidated statements of financial position. The amortization of the Colowyo Coal intangible liability is accounted for as an increase in other operating revenue. An amortization benefit of $3.3, $2.9 and $3.2 million was recognized in 2017, 2016 and 2015, respectively.

NOTE 5 – LONG-TERM DEBT

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 two unsecured notes in the aggregate amount of $41.5 million as of December 31, 2017. 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 and ECR requirement.

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

	December 31, 2017	December 31, 2016
Mortgage notes payable		
3.66% to 8.08% CFC, due through 2028	$ 80,948	$ 83,653
2.63% to 6.17% CoBank, ACB, due through 2042	257,630	268,045
First Mortgage Obligations, Series 2017A, Tranche 1, 3.34%, due through 2029	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 1, 6.00%, due through 2019	54,286	81,429
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	88,000	110,000
Variable rate CFC, as determined by CFC, due through 2026	549	598
Variable rate CFC, LIBOR-based term loan, due through 2049	102,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loan, due through 2044	102,220	102,220
Pollution control revenue bonds		
City of Gallup, NM, 5.00%, Series 2005, due through 2017	—	5,540
Moffat County, CO, 2.00% term rate through October 2022, Series 2009, due 2036	46,800	46,800
Springerville certificates		
Series A, 6.04%, due through 2018	13,721	52,994
Series B, 7.14%, due through 2033	405,000	405,000
Other	47	1,222
Total debt	$ 3,211,421	$ 3,259,721
Less debt issuance costs	(21,720)	(22,255)
Less debt discounts	(10,360)	(10,569)
Plus debt premiums	18,949	20,711
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,198,290	$ 3,247,608
Less current maturities	(78,004)	(107,903)
Long-term debt	$ 3,120,286	$ 3,139,705

We have a secured revolving credit facility with Bank of America, N.A. ("Bank of America") and CoBank, ACB as Joint Lead Arrangers in the amount of $750 million ("Revolving Credit Agreement") extending through July 26, 2019. We had no outstanding borrowings at December 31, 2017 and no outstanding borrowings at December 31, 2016. As of December 31, 2017, we have $605.0 million in availability (including $355.0 million under the commercial paper back-up sublimit) under the Revolving Credit Agreement. We expect to renew or replace the Revolving Credit Agreement prior to its expiration.

On May 23, 2016, we issued our First Mortgage Bonds, Series 2016A ("Series 2016A Bonds") in an unregistered offering pursuant to Rule 144A under the Securities Act of 1933, as amended, with an aggregate principal amount of $250 million. The Series 2016A Bonds mature on June 1, 2046 and bear interest at a rate of 4.25 percent per annum. We utilized the proceeds from the Series 2016A Bonds primarily to repay outstanding indebtedness under the Revolving Credit Agreement. In connection with the Series 2016A Bonds, we entered into an exchange and registration rights agreement pursuant to which we agreed to file a registration statement relating to an exchange offer for our Series

2016A Bonds. On June 27, 2016, we commenced an offer to exchange all of the unregistered $250 million aggregate principal amount of the Series 2016A Bonds for $250 million aggregate principal amount of registered Series 2016A Bonds. We completed the exchange offer in July 2016 which satisfied our obligations under the exchange and registration rights agreement. The exchange offer did not represent a new financing transaction and there were no proceeds to us when the exchange offer was completed.

On October 2, 2017, we converted our Moffat County, CO pollution control revenue bonds from a weekly variable rate mode to a five-year term rate mode at a rate of 2.0 percent ending October 3, 2022. On October 17, 2017, the letter of credit issued under the Revolving Credit Agreement to support the variable rate demand bonds was terminated.

On November 16, 2017, we entered into a Note Purchase Agreement with a group of institutional investors to sell our First Mortgage Obligations, Series 2017A in an aggregate principal amount of $120 million, consisting of $60 million of our 3.34 percent First Mortgage Obligations, Series 2017A Notes, Tranche 1, due December 12, 2029, and $60 million of our 3.39 percent First Mortgage Obligations, Series 2017A Notes, Tranche 2, due December 12, 2029 in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended. The closing of the sale of the Series 2017A Notes, Tranche 1 occurred on December 12, 2017 and the closing of the sale of the Series 2017A Notes, Tranche 2 is expected to occur on April 12, 2018, subject to the satisfaction of certain conditions.

Annual maturities of total debt adjusted for debt issuance costs, discounts and premiums at December 31, 2017 are as follows (dollars in thousands):

2018	$ 78,004
2019	97,443
2020	84,499
2021	90,760
2022	96,333
Thereafter	2,751,251
	$ 3,198,290

We are exposed to certain risks in the normal course of operations in providing a reliable and affordable source of wholesale electricity to our Members. These risks include interest rate risk, which represents the risk of increased operating expenses and higher rates due to increases in interest rates related to future long-term borrowings. To manage this exposure, we entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate exposure. On October 12, 2017, in conjunction with the pricing on the offering of the First Mortgage Obligations, Series 2017A, we settled the interest rate swap entered into in April 2016, which resulted in a realized gain of $4.6 million that has been deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A. We anticipate settling the remaining interest rate swap in conjunction with the issuance of future long-term debt. See Note 2 – Accounting for Rate Regulation and Note 7 – Fair Value.

The terms of the remaining interest rate swap contract are as follows (dollars in thousands):

	Notional Amount	Fixed Rate (Pay)	Benchmark Interest Rate (Receive)	Effective Date	Maturity Date
Interest rate swap - June 2016	$ 80,000	2.304 %	30 year - LIBOR	June 2019	June 2049

NOTE 6 – SHORT-TERM BORROWINGS

We established a commercial paper program in May 2016 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 (dollars in thousands):

	2017	2016
Commercial paper outstanding, net of discounts	$ 144,667	$ 119,901
Weighted average interest rate	1.52 %	0.89 %

At December 31, 2017, $355.0 million of the commercial paper back-up sublimit remained available under the Revolving Credit Agreement. See Note 5 – Long-term Debt.

NOTE 7 – 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 classified as available-for-sale and are measured at fair value on a recurring basis. 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 unrealized gains are reported as a component of accumulated other comprehensive income. The amortized cost and fair values of our marketable securities are as follows (dollars in thousands):

	December 31, 2017		December 31, 2016	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Marketable securities	$ 1,007	$ 1,166	$ 987	$ 1,103

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 $109.4 million and $49.1 million as of December 31, 2017 and 2016, 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, 2017		December 31, 2016	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,211,421	$ 3,600,650	$ 3,259,721	$ 3,543,640

Interest Rate Swaps

We entered into forward starting interest rate swaps in 2016 to hedge a portion of our future long-term debt interest rate expense. See Note 5 – Long-Term Debt. These interest rate swaps are derivative instruments in accordance with ASC 815, Derivatives and Hedging, and are recorded at fair value on a recurring basis. The estimated fair value of these interest rate swaps utilizes 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) and are included in other deferred charges on our consolidated statements of financial position. At December 31, 2017, the fair value of our interest rate swap was an unrealized gain of $4.3 million, which was deferred in accordance with our regulatory accounting. On October 12, 2017, we settled the interest rate swap entered into in April 2016, which resulted in a realized gain of $4.6 million. In accordance with regulatory accounting, the settled interest rate swap gain was deferred and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A. See Note 2 – Summary of Significant Accounting Policies.

NOTE 8 – INCOME TAXES

We had an income tax benefit of $1.1 and $1.4 million in 2017 and 2016, respectively, and no income tax expense or benefit in 2015. The income tax benefit of $1.1 million in 2017 is 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. In accordance with our regulatory accounting treatment, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current portion.

Under the liability method, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and for income tax purposes.

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

	December 31, 2017	December 31, 2016
Deferred tax assets		
Safe harbor lease receivables	$ 19,222	$ 33,355
Net operating loss carryforwards	104,102	142,286
Alternative minimum tax credit carryforwards	1,230	2,417
Deferred revenues and membership withdrawal	17,350	30,583
Colowyo Coal- coal contract intangible liability	—	1,228
Other	23,707	41,066
	165,611	250,935
Deferred tax liabilities		
Basis differences- property, plant and equipment	112,285	162,928
Capital credits from other associations	28,787	44,268
Deferred debt prepayment transaction costs	37,649	62,773
Other	4,095	11,483
	182,816	281,452
Net deferred tax liability	$ (17,205)	$ (30,517)

The decrease in the net deferred tax liability from $30.5 million at December 31, 2016 to $17.2 million at December 31, 2017 is primarily due to a $17.2 million decrease in the net deferred tax liability resulting from a reduction in the corporate income tax rate. The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the corporate income tax rate from 35 percent to 21 percent effective January 1, 2018. Deferred tax assets and deferred tax liabilities at December 31, 2017 are measured at 21 percent, which is the rate in effect when the book to tax differences that comprise the net deferred tax liability reverse. Although the $17.2 million decrease in the net deferred tax liability and the corresponding decrease in the regulatory asset established for deferred income tax expense represent what we believe to be a reasonable estimate of the impact of the income tax effect of the Tax Cuts and Jobs Act on our financial statements as of December 31, 2017, this assessment should be considered provisional. After we finalize certain tax positions when we file our 2017 U.S. tax return, we will be able to conclude whether any further adjustments are required to our net deferred tax liability balance of $17.2 million as of December 31, 2017. Any adjustments to these provisional amounts will be reported in the period the adjustments are made, which will be no later than the fourth quarter of 2018.

The $13.3 million decrease in net deferred tax liabilities is not recognized as a tax benefit in 2017 due to our regulatory accounting treatment of deferred taxes. Instead, the tax benefit 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 account for deferred income tax expense has a balance of $17.2 million and $30.5 million at December 31, 2017 and 2016, respectively.

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

	2017	2016	2015
Federal income tax expense at statutory rate	35.00 %	35.00 %	35.00 %
State income tax expense, net of federal benefit	2.63	2.63	2.63
Patronage exclusion	(37.63)	(37.63)	(37.63)
Asset retirement obligations	(0.16)	5.85	(0.58)
Postretirement medical actuarial gains and losses	0.02	1.04	(1.09)
Various book tax differences	2.27	(7.66)	2.84
Regulatory treatment of deferred taxes	(3.91)	(3.79)	(1.17)
Effective tax rate	(1.78)%	(4.56)%	0.00 %

We had a taxable loss of $63.7 million for 2017. At December 31, 2017, we have a federal net operating loss carryforward of $439.1 million which, if not utilized, will expire between 2030 and 2037. The future reversal of existing temporary differences will more likely than not enable the realization of the net operating loss carryforward. We have $1.2 million of alternative minimum tax credit carryforwards at December 31, 2017 that have no expiration date.

The authoritative guidance for income taxes addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. We may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement.

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 2014 forward. We do not have any liabilities recorded for uncertain tax positions.

NOTE 9 – LEASES

LESSOR—GAS TOLLING ARRANGEMENTS: We are the lessor under a power sales arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys the right to use power generating equipment for a stated period of time. This arrangement includes a sales contract to a third party out of our J.M. Shafer Generating Station. The third party directs the use of 122 megawatts of the 272 megawatt generating capability of the J.M. Shafer Generating Station through June 30, 2019 under a tolling arrangement whereby the third party provides its own natural gas for generation of electricity. Through April 2016, a third party directed the use of both of the two Knutson Generating Station units and one of the two Limon Generating Station units under tolling arrangements whereby the third party provided its own natural gas for generation of electricity. The revenues from these operating leases of $11.6, $17.1 and $30.1 million for 2017, 2016 and 2015, respectively, are accounted for as lease revenue and are reflected in other operating revenue on our consolidated statements of operations. The generating units used in these gas tolling arrangements have a total cost and accumulated depreciation of $111 and $63 million, respectively, as of December 31, 2017, and of $114 and $63 million, respectively, as of December 31, 2016.

The minimum future lease revenues under these gas tolling arrangements at December 31, 2017 are as follows (dollars in thousands):

2018	$ 11,586
2019	5,793
	$ 17,379

LESSEE—GAS TOLLING ARRANGEMENT: We are the lessee under a power purchase arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time. Under this agreement, we direct the use of 70 megawatts at the Brush Generating Station for a 10-year term ending December 31, 2019 and provide our own natural gas for generation of electricity. The expense for the Brush operating lease of $5.3 million for each of the years 2017, 2016 and 2015 is included in other operating expenses on our consolidated statements of operations. Our operating lease commitments for this gas tolling arrangement at December 31, 2017 are as follows (dollars in thousands):

2018	$ 5,855
2019	6,031
	$ 11,886

NOTE 10 – RELATED PARTIES

TRAPPER MINING, INC.: We, and certain participants in the Yampa Project, own Trapper Mining. Organized as a cooperative, Trapper Mining supplied 24.7, 26.2 and 25.7 percent in 2017, 2016 and 2015, respectively, of the coal for the Yampa Project. Our 26.57 percent share of coal purchases from Trapper Mining was $18.8, $16.9 and $17.7 million in 2017, 2016 and 2015, respectively. Our membership interest in Trapper Mining of $15.0 and $14.5 million at December 31, 2017 and 2016, respectively, is included in investments in and advances to coal mines on our consolidated statements of financial position.

NOTE 11 – EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,546 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan (“RS Plan”) except for the 222 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 53-0116145 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 2017, 2016 and 2015 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 $26.7, $24.8 and $22.9 million in 2017, 2016 and 2015, respectively.

In December 2012, the National Rural Electric Cooperative Association 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 319 bargaining unit employees that are made in accordance with collective bargaining agreements.

In 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 January 1, 2017, and over 80 percent funded at January 1, 2016, 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.

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 319 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the 222 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 $3.2 million for 2017 and $3.0 million for 2016 and 2015.

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, 2017, 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 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):

	2017	2016
Postretirement medical benefit obligation at beginning of year	$ 7,997	$ 6,723
Service cost	607	549
Interest cost	281	285
Benefit payments (net of contributions by participants)	(324)	(381)
Actuarial (gain) loss	(106)	821
Postretirement medical benefit obligation at end of year	$ 8,455	$ 7,997
Postemployment medical benefit obligation at end of year	367	178
Total postretirement and postemployment medical obligations at end of year	$ 8,822	$ 8,175

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):

	2017	2016
Amounts included in accumulated other comprehensive income at beginning of year	$ (402)	$ 460
Amortization of actuarial loss into income	6	38
Amortization of prior service credit into income	(79)	(79)
Actuarial gain (loss)	106	(821)
Amounts included in accumulated other comprehensive income at end of year	$ (369)	$ (402)

The assumptions used in the 2017 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.44 %
Initial health care cost trend (2017)	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)	12.32

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	$ 931	$ (803)
Net periodic postretirement medical benefit expense	138	(115)

The following are the expected future benefits to be paid related to the postretirement medical benefit obligation during the next 10 years (dollars in thousands):

2018	$ 412
2019	507
2020	562
2021	586
2022	659
2023 through 2027	3,335
	$ 6,061

NOTE 12 – 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.

Our consolidated statements of financial position include the Springerville Partnership's net electric plant of $812.7 million and $832.3 million at December 31, 2017 and 2016, respectively, the long-term debt of $431.3 million (including debt premiums) and $472.1 million (including debt premiums) at December 31, 2017 and 2016, respectively, accrued interest associated with the long-term debt of $12.4 million and $13.4 million at December 31, 2017 and 2016, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $111.3 million and $109.1 million at December 31, 2017 and 2016, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $19.6 million for 2017 and $21.0 million for 2016 and 2015. Our consolidated statements of operations also include interest expense of $28.4, $30.4 and $32.3 million for 2017, 2016 and 2015, respectively. 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. The revenue associated with the Springerville Partnership lease has been eliminated in consolidation. Income, losses and cash flows of the Springerville Partnership are allocated to the general and limited partners based on their equity ownership percentages.

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 includes us. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in WFW. We also receive 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 have 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 are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.3 million and $2.2 million for December 31, 2017 and 2016, respectively, 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 24.13 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 have 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.

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 have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There is not sufficient equity at risk for Trapper Mining to finance its activities without additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which we have 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) is shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $15.0 million and $14.5 million at December 31, 2017 and 2016, respectively, and is included in investments in and advances to coal mines.

NOTE 13 – COMMITMENTS AND CONTINGENCIES

SALES: We have delivery obligations under resource-contingent power sales contracts with Salt River Project Agricultural Improvement and Power District of 100 megawatts through August 31, 2036. We also had a resource-contingent firm power sales contract with Public Service Company of Colorado totaling 100 megawatts. This contract expired in March 2017.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under long-term contracts that expire between 2019 and 2034. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions. The projection of contractually committed purchases is based upon estimated future prices. At December 31, 2017, the annual minimum coal purchases under these contracts are as follows (dollars in thousands):

2018	$ 106,908
2019	109,403
2020	79,048
2021	57,700
2022	3,279
Thereafter	2,654
	$ 358,992

ELECTRIC POWER PURCHASE AGREEMENTS: Our principal long-term electric power purchase contracts are with Western Area Power Administration ("WAPA") and Basin. WAPA markets and supplies cost-based hydroelectric power and related services primarily to cooperatives and municipal electric systems, and certain other "preference" customers located in 15 states in the central and western part of the United States. WAPA sells power to us pursuant to three contracts: one relating to WAPA's Loveland Area Project (terminates September 30, 2024), and two contracts relating to WAPA's Salt Lake City Area Integrated Projects (both terminate September 30, 2024). In 2015, we entered into a new contract with WAPA relating to the Loveland Area Project for the delivery of power from WAPA beginning October 1, 2024 and ending September 30, 2054.

Basin sells power to us pursuant to two contracts: one relating to all the power which we require to serve our 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.

In addition to our contracts with WAPA for hydroelectric power purchases, we have entered into various renewable power purchase contracts to purchase the entire output from the applicable renewable facilities totaling approximately 477 MWs, including 367 MWs of wind-based power purchase agreements and 85 MWs of solar-based power purchases.

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

	2017	2016	2015
Basin	$ 152,977	$ 145,557	$ 127,500
WAPA	78,781	82,575	89,986
Wind and Solar	53,362	42,292	29,308

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 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. We cannot predict at this time whether any additional legislation or rules will be enacted which will affect our operations, and if such laws or rules are enacted, what the cost to us might be in the future because of such actions or the effect it could have on our financial condition, results of operations and cash flow.

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

LEGAL: In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five weeks in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, composed of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, Jemez Mountains Electric Cooperative, Inc. ("JMEC") in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs alleged that the fire ignited when a tree growing outside JMEC's right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. After JMEC settled with one plaintiff group, the remaining cases were Elizabeth Ora Cox, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Norman Armijo, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Esequiel Espinoza, et al. v. Allstate Property & Casualty, et al.; Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et al.; and Pueblo de Cochiti., et al. v. Jemez Mountains Electric Cooperative, Inc., et al. The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we were also jointly liable for any negligence by JMEC under joint venture and joint enterprise theories. A jury trial commenced on September 28, 2015 on the liability aspect of this matter. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. JMEC has resolved all claims against it, and the terms of the resolution are confidential. Although we have not settled this matter, we have reached separate confidential stipulations on damages with all plaintiff groups, reserving the right to appeal liability issues. We maintain $100 million in liability insurance coverage for this matter. On September 12 and 25, 2017, we filed notices to appeal to the New Mexico Court of Appeals the determination of our liability for this matter. The plaintiffs have filed cross-appeals on their joint venture and joint enterprise claims. If we do not prevail on appeal, we expect our allocation of damages to be covered by our liability insurance. Although we cannot predict the outcome of this matter at this point in time, we do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

Pursuant to a 30 year power sales contract with another utility that expires in 2020, we currently sell such utility 25 MWs of capacity and energy. The purchase rate for capacity is determined using our Class A wholesale rate schedule. The utility has recently reviewed our charges for capacity since 2000 and alleges such charges are not in accordance with the terms of the power sales contract. We are in discussions with the utility regarding their review of our charges for capacity and no formal dispute resolution process has commenced. It is not possible to predict whether we will incur any liability or to reasonably estimate the amount or range of loss, if any, we might incur in connection with this matter.

NOTE 14 – QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2017 and 2016 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
2017					
Operating revenues	$ 338,429	$ 338,901	$ 396,511	$ 314,752	$ 1,388,593
Operating margins	51,018	36,970	74,946	20,763	183,697
Net margins attributable to the Association	23,526	4,791	40,798	(7,459)	61,656
2016					
Operating revenues	$ 323,462	$ 320,622 (1)	$ 378,352 (1)	$ 318,660 (1)	$ 1,341,096
Operating margins	46,379	37,003	52,199	11,425	147,006
Net margins attributable to the Association	17,533	2,537	17,739	(6,061)	31,748

(1) A power agreement is being presented net for 2016 whereas previous year quarterly presentations were gross.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this annual report, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that as of December 31, 2017 our disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

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

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on this assessment, management believes that we maintained effective internal control over financial reporting as of December 31, 2017.

Changes in Internal Control over Financial Reporting

There were no changes that occurred during the fourth quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

Our Board is comprised of one representative from each of our 43 Members. Each Member elects its representative to serve on our Board. Each of our directors must be a general manager, director or trustee of a Member. Except as otherwise provided in our Bylaws, the term of each director is from the time he or she is elected by its Member and such election is certified in writing to us by such Member until such Member elects another person to serve and the fact of such election is certified in writing to us by such Member. Each representative on our Board brings an understanding of our Members' business and brings insight to our Members' operations which we believe qualifies them to serve on our Board. The members of our Board and their ages as of March 1, 2018 are as follows:

NAME	AGE	MEMBER-REPRESENTATIVE
Rick Gordon—Chairman and President	64	Mountain View Electric Association, Inc.
Leo Brekel—Vice Chairman	66	Highline Electric Association
Julie Kilty—Secretary	59	Wyrulec Company
Stuart Morgan—Treasurer	71	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	66	High Plains Power, Inc.
Donald Keairns—Assistant Secretary	58	San Isabel Electric Association, Inc.
Arthur W. Connell —Executive Committee	64	Central New Mexico Electric Cooperative, Inc.
William Mollenkopf—Executive Committee	68	Empire Electric Association, Inc.
Timothy Rabon—Executive Committee	57	Otero County Electric Cooperative, Inc.
Robert Baca	53	Mora-San Miguel Electric Cooperative, Inc.
Robert Bledsoe	68	K.C. Electric Association
Jerry Burnett	71	High West Energy, Inc.
Richard Clifton	76	Carbon Power & Light, Inc.
Lucas Cordova Jr.	52	Jemez Mountains Electric Cooperative, Inc.
John "Jack" Finnerty	78	Wheatland Rural Electric Association
Gary Fuchser	63	Northwest Rural Public Power District
Jack Hammond	83	Niobrara Electric Association, Inc.
Ronald Hilkey	78	White River Electric Association, Inc.
Ralph Hilyard	79	Roosevelt Public Power District
Donald L. Kaufman	79	Sangre de Cristo Electric Association, Inc.
Hal Keeler	89	Columbus Electric Cooperative, Inc.
Kyle S. Martinez	29	Delta-Montrose Electric Association
Kohler McInnis	63	La Plata Electric Association, Inc.
Thaine Michie	77	Poudre Valley Rural Electric Association, Inc.
Christopher Morgan	49	Gunnison County Electric Association, Inc.
Richard Newman	67	United Power, Inc.
Stanley Propp	71	Chimney Rock Public Power District
Steve M. Rendon	63	Northern Rio Arriba Electric Cooperative, Inc.
Claudio Romero	71	Continental Divide Electric Cooperative, Inc.
Peggy A. Ruble	64	Garland Light & Power Company
Donald Russell	70	Big Horn Rural Electric Company
Brian Schlagel	68	Morgan County Rural Electric Association
Donald Schutz	71	Springer Electric Cooperative, Inc.
Jack Sibold	72	San Miguel Power Association, Inc.
Charles J. Soehner	73	Y-W Electric Association, Inc.
Darryl Sullivan	67	Sierra Electric Cooperative, Inc.
Travis Sullivan	46	Southwestern Electric Cooperative, Inc.
Carl Trick II	70	Mountain Parks Electric, Inc.
Douglas Shawn Turner	56	The Midwest Electric Cooperative Corporation
Donald Wolberg	75	Socorro Electric Cooperative, Inc.
Scott Wolfe	54	San Luis Valley Rural Electric Cooperative, Inc.
William Wright	77	Southeast Colorado Power Association
Phillip Zochol	42	Panhandle Rural Electric Membership Association

Rick Gordon has served on our Board since November 1994 and is Chairman and President of the Board. He is a member of the Executive Committee, as well as Ex-Officio of the Engineering and Operations Committee, the External Affairs-Member Relations Committee, and the Finance and Audit Committee. Mr. Gordon serves as a director of Mountain View Electric Association, Inc. He also serves as a director of Elk Ridge, WFA, and Trapper Mining. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Calhan, Flagler, Limon and Sterling, Colorado.

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

Julie Kilty has served on our Board since January 2013 and is Secretary of the Board. She is a member of the Executive Committee and External Affairs-Member Relations Committee. Ms. Kilty serves as Treasurer of Wyrulec Company. She is owner of Bar X Ranch, LLC.

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

Matt M. Brown has served on our Board since April 2010 and is Assistant Secretary of the Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Brown serves as a director of High Plains Power, Inc. He is a rancher in Thermopolis, Wyoming and has held a real estate license in Wyoming since 1983.

Donald Keairns has served on our Board since April 2012 and is Assistant Secretary of the Board. He is a member of the Executive Committee and the Finance and Audit Committee. Mr. Keairns serves as a director of San Isabel Electric Association, Inc. He was owner and operator of a small grocery business. He currently owns and manages several rental properties. Mr. Keairns also serves as a director of Western United Electric Supply Corporation.

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

William Mollenkopf has served on our Board since June 2009. He is a member of the Executive Committee and Finance and Audit Committee. Mr. Mollenkopf serves as a director of Empire Electric Association, Inc. He is a retired optometrist.

Timothy Rabon has served on our Board since April 2014. He is a member of the Executive Committee and Engineering and Operations Committee. Mr. Rabon serves as a trustee of Otero County Electric Cooperative, Inc. He is President of Mesa Verde Enterprises, Inc., which is a heavy horizontal civil construction company. He is the Vice President of Heritage Group, which is a commercial and residential land development company. He is also a partner of Mesa Verde Ranch LLP, which is a land holding and cow/calf ranching operation. He owns Aggregate Technologies, LLC, which is a mining and aggregate production and trucking operation. He is also owner of MV2, LLC, which is a land holding and construction and demolition landfill operation, and Vice President and co-owner of Trabon LLC, which is a trucking and property management company.

Robert Baca has served on our Board since June 2016. He is a member of the External Affairs-Member Relations Committee. Mr. Baca serves as Vice Chairman of Mora-San Miguel Electric Cooperative, Inc. He is a self-employed electrician and owner of EGB Electric since 1992.

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

Jerry Burnett has served on our Board since November 2013. He is a member of the Engineering and Operations Committee. Mr. Burnett serves as Vice President of High West Energy, Inc. He is a real estate broker, as well as a farmer, rancher and dairyman in Hereford, Colorado. Mr. Burnett is also on the board of directors of Coldwell Banker and TPE.

Richard Clifton has served on our Board since June 2009. He is a member of the Finance and Audit Committee. Mr. Clifton serves as a director of Carbon Power & Light, Inc. Mr. Clifton is also President on the board of directors of Wyoming Rural Electric Association.

Lucas Cordova Jr. has served on our Board since August 2013. He is a member of the Engineering and Operations Committee. Mr. Cordova serves as a trustee of Jemez Mountains Electric Cooperative, Inc. He is also the owner of Aspen Tree and Crane Service, LLC.

John "Jack" Finnerty has served on our Board since April 1988. He serves as Chairman of the Engineering and Operations Committee. Mr. Finnerty serves as Secretary/Treasurer of Wheatland Rural Electric Association. He is also a rancher in Wheatland, Wyoming. Mr. Finnerty also serves as a director of Elk Ridge.

Gary Fuchser has served on our Board since August 2013. He is a member of the Engineering and Operations Committee. Mr. Fuchser serves as a director of Northwest Rural Public Power District. He is a farmer in Gordon, Nebraska and the President of Fuchser Farms Inc.

Jack Hammond has served on our Board since January 2005. He is a member of the External Affairs-Member Relations Committee. Mr. Hammond serves as a director of Niobrara Electric Association, Inc. He is a retired oil field contractor.

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

Ralph Hilyard has served on our Board since April 2002. He is a member of the Engineering and Operations Committee. Mr. Hilyard serves as a director of Roosevelt Public Power District. He is a retired self-employed farmer.

Donald L. Kaufman has served on our Board since June 2015. He is a member of the External Affairs-Member Relations Committee. Mr. Kaufman serves as President of Sangre de Cristo Electric Association, Inc. He is retired from the United States Air Force. Mr. Kaufman also serves as a director and the Secretary/Treasurer for the Wet Mountain Valley Community Foundation.

Hal Keeler has served on our Board since July 2000. He is a member of the Finance and Audit Committee. Mr. Keeler serves as a trustee of Columbus Electric Cooperative, Inc. He is a retired farm owner-operator and has also been a bank board member for 1st New Mexico Bank for 21 years. He also serves as a director of WFA.

Kyle S. Martinez has served on our Board since July 2017. He is a member of the External Affairs-Member Relations Committee. Mr. Martinez serves as director of Delta-Montrose Electric Association. He is employed by Touch of Care, where he manages operations in multiple rural Colorado towns. Mr. Martinez also owns and operates a farm in Olathe, Colorado.

Kohler McInnis has served on our Board since June 2017. He is a member of the External-Affairs-Member Relations Committee. Mr. McInnis serves as a director of La Plata Electric Association, Inc. Mr. McInnis was the owner and operator of a printing business. He currently is an investor in and manager of various Colorado investment companies.

Thaine Michie has served on our Board since March 2009. He is a member of the External Affairs-Member Relations Committee. Mr. Michie serves as a director of Poudre Valley Rural Electric Association, Inc. He is a retired Chief Executive Officer of Platte River Power Authority. Mr. Michie also serves as a director of Elk Ridge.

Christopher Morgan served on our Board from June 2012 until February 2015 and he was re-elected to our Board in April 2015. He is a member of the Finance and Audit Committee. He serves as a director of Gunnison County Electric Association, Inc. He manages rental property and is self-employed. Mr. Morgan is also a founding board member of the Office of Resource Efficiency and the Gunnison Valley Rural Transportation Authority. He is a past council member of 13 years and past mayor of the town of Mt. Crested Butte.

Richard Newman has served on our Board since January 2012. He is the Chairman of the External Affairs-Member Relations Committee. Mr. Newman serves as a director of United Power, Inc. He is President of Thoro Products Co., a past building manager for Bluhill Park Partners, and a partner in the Gilpin Aerial Tram Enterprise.

Stanley Propp has served on our Board since April 2015. He is a member of the External Affairs-Member Relations Committee. He serves as a director of Chimney Rock Public Power District. He is a retired farmer and is currently the shop foreman of Scottsbluff County Weed Control Authority.

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

Claudio Romero has served on our Board since June 2001. He is a member of the Finance and Audit Committee. Mr. Romero serves as a trustee of Continental Divide Electric Cooperative, Inc. He is self-employed in electrical construction.

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

Donald Russell has served on our Board since March 2012. He is a member of the Finance and Audit Committee. Mr. Russell serves as Treasurer of Big Horn Rural Electric Company. He is a partner in the CPA Firm of Russell and Russell. He is also a partner in the farming operation of Russell Land & Livestock.

Brian Schlagel has served on our Board since May 2005. He is a member of the Finance and Audit Committee. Mr. Schlagel serves as a director of Morgan County Rural Electric Association. He is a half owner of Schlagel Farms.

Donald Schutz has served on our Board since August 2015. He is a member of the External Affairs-Member Relations Committee. Mr. Schutz serves as President of Springer Electric Cooperative, Inc. He is a rancher in northeastern New Mexico and the Vice-President and general manager of the S & S Ranch Company.

Jack Sibold has served on our Board since June 2014. He is a member of the Engineering and Operations Committee. Mr. Sibold serves as a director of San Miguel Power Association, Inc. He is a director of Tri-County Water Conservancy District. As the former director of R&D for Coorstek, he has been engaged in ceramic engineering consulting.

Charles J. Soehner has served on our Board since April 1991. He is a member of the Engineering and Operations Committee. Mr. Soehner serves as a director of Y-W Electric Association, Inc. He is a sole proprietor/operator of a farm and ranch in Wray, Colorado. Mr. Soehner also serves as a director of Elk Ridge.

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

Travis Sullivan has served on our Board since January 2018. He is a member of the External Affairs-Member Relations Committee. Mr. Sullivan is the General Manager of Southwestern Electric Cooperative, Inc.

Carl Trick II has served on our Board since September 2012. He is a member of the Engineering and Operations Committee. Mr. Trick serves as the Assistant Secretary/Treasurer of Mountain Parks Electric, Inc. He is the President and owner of North Park Angus Ranch, Inc., a cattle and hay operation in North Park, Colorado. Mr. Trick also serves as a director of Trapper Mining.

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

Donald Wolberg has served on our Board since April 2016. He is a member of the External Affairs-Member Relations Committee. Mr. Wolberg serves as a trustee of Socorro Electric Cooperative, Inc. He is an adjunct professor at the New Mexico Institute of Mining and Technology.

Scott Wolfe has served on our Board since June 2008. He is a member of the Finance and Audit Committee. Mr. Wolfe serves as Secretary/Treasurer of San Luis Valley Rural Electric Cooperative, Inc. He is a farmer and owner of Lobo Farm LLC.

William Wright has served on our Board from April 1994 until November 2018 and he was re-elected to our Board in January 2018. He is a member of the Engineering and Operations Committee. Mr. Wright serves as a director of Southeast Colorado Power Association and is an owner/farmer of Wright Farms.

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

Audit Committee Financial Expert

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

Executive Officers

The following table sets forth the names and positions of our executive officers and their ages as of March 1, 2018:

NAME	AGE	POSITION
Micheal S. McInnes	65	Chief Executive Officer
Joel Bladow	58	Senior Vice President, Transmission
Patrick L. Bridges	59	Senior Vice President/Chief Financial Officer
Ellen Connor	60	Senior Vice President, Organizational Services/Chief Technology Officer
Jennifer Goss	48	Senior Vice President, Member Relations
Barry Ingold	54	Senior Vice President, Generation
Bradford Nebergall	59	Senior Vice President, Energy Management
Kenneth V. Reif	66	Senior Vice President, General Counsel
Barbara Walz	55	Senior Vice President, Policy & Compliance/Chief Compliance Officer

Micheal S. McInnes is our Chief Executive Officer and has served in that position since 2014. Mr. McInnes previously served as Senior Vice President, Production prior to that position. He has been employed with Tri-State since July 2000, following the merger of Plains Electric Generation and Transmission Cooperative, Inc. into Tri-State. Previously, he served as Executive Vice President and General Manager of Plains Electric Generation and Transmission

Cooperative, Inc. and has 19 years of experience in generating facility generation and operations, including Plant Manager, Director of Generation and Executive Manager of Generation Operations. Mr. McInnes has over 35 years of experience in the electric utility industry.

Joel Bladow is our Senior Vice President, Transmission and has served in that position since 2006. Prior to joining Tri-State, Mr. Bladow was a member of WAPA's senior management team and has over 35 years of experience in the electric utility industry. Mr. Bladow has a master's degree in electrical engineering and is a registered professional engineer in Colorado.

Patrick L. Bridges is our Senior Vice President/Chief Financial Officer and has served in that position since 2008. Mr. Bridges previously served as Senior Manager, Corporate Finance. Prior to joining Tri-State in 2006, he served as the Vice President and Treasurer of Texas-New Mexico Power Company. Mr. Bridges has over 35 years of experience in the electric energy sector. He has a Master of Science degree in applied economics from the University of Texas at Dallas, a Master of Business Administration and a Bachelor of Business Administration degree from West Texas State University, and is a Certified Public Accountant, inactive, and Chartered Financial Analyst.

Ellen Connor is our Senior Vice President, Organizational Services/Chief Technology Officer and has served in that position since 2014. Ms. Connor previously served as Senior Manager, Financial Planning & Analysis and Insurance. Previous roles at Tri-State included Senior Manager, Enterprise Risk Management, and management of various finance functions. Prior to Tri-State's merger with Plains Electric Generation and Transmission Cooperative, Inc. in 2000, Ms. Connor served as Chief Financial Officer of Plains Electric Generation and Transmission Cooperative, Inc. Ms. Connor has a Bachelor of Science in business administration and is a Certified Treasury Professional. Ms. Connor has over 35 years of experience in the electric utility industry.

Jennifer Goss is our Senior Vice President, Member Relations and has served in that position since 2013. Prior to joining Tri-State, Mrs. Goss served from 2011 to 2013 as chief operating officer and chief financial officer for Green Energy Corp. Mrs. Goss previously served at CoBank, joining the bank in 1998 and serving as senior vice president of the electric distribution lending division and a member of the senior leadership team since 2003. She has held various positions at Fleet Financial Group and Phoenix Home Life Insurance Company. Mrs. Goss has a bachelor's degree in English literature from Assumption College. Mrs. Goss has 19 years of electric utility experience.

Barry Ingold is our Senior Vice President, Generation and has served in that position since 2014. Mr. Ingold previously served as Senior Manager, Production Assets and has served in numerous engineering and management roles since joining Tri-State in 2004. In addition to his 20 years of direct industry experience, Mr. Ingold served for 13 years in the submarine force of the United States Navy. He then transitioned to the Navy Reserve where he served for an additional 13 years and attained the rank of Captain prior to retiring from the United States Navy. Mr. Ingold has a bachelor's degree in marine engineering and marine transportation from the United States Merchant Marine Academy, a master's degree in mechanical engineering from the Naval Postgraduate School, and a master's degree in business administration from Arizona State University.

Bradford Nebergall is our Senior Vice President, Energy Management and has served in that position since 2008. Prior to joining Tri-State in 2007, Mr. Nebergall was the chief operating officer for Enron Renewable Energy Corp. He also held various positions at Enron Corp. and Norwest Bank (now Wells Fargo Bank). Mr. Nebergall has a Master's of Business Administration degree from the University of Houston and a Bachelor of Science degree in finance from Iowa State University. Mr. Nebergall has 31 years of experience in the energy industry.

Kenneth V. Reif is our Senior Vice President, General Counsel and has served in that position since 2004. Prior to joining Tri-State, Mr. Reif was Director of Colorado Office of Consumer Counsel representing residential, small business and agricultural utility consumers before the Colorado Public Utilities Commission and federal regulators. Prior to 1996, he practiced utility law in Denver, Colorado, first as a partner at Kelly, Stansfield and O'Donnell, and then as counsel at LeBoeuf, Lamb, Greene and MacRae. Mr. Reif has a Bachelor of Arts degree from California Polytechnic State University and a Jurisprudence Doctor degree from the University of Denver. He has 38 years of utility experience.

Barbara Walz is our Senior Vice President, Policy & Compliance/Chief Compliance Officer and has served in that position since 2011. She joined Tri-State in 1997 as senior engineer of environmental services. She has held various positions at Tri-State, including Environmental Services Manager and later, Vice President of Environmental. Mrs. Walz has a Bachelor of Science degree in chemical engineering from the University of North Dakota, a master's degree in environmental policy and management from the University of Denver, and a certificate in Financial Success for Nonprofits from Cornell University. In 2017, Mrs. Walz was inducted in to the University of North Dakota Engineering Hall of Fame. She has 21 years of experience in the utility industry.

Code of Ethics

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

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

General Philosophy

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

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

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

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

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

Retention Agreements. The Chief Executive Officer, with the approval of the Board, has in the past executed retention agreements for certain executive officers as deemed appropriate.

Retirement Plans

Defined Benefit Plan. We participate in the RS Plan, a noncontributory, defined benefit multiple employer master pension plan which is available to all of our employees as well as certain employees of one of our subsidiaries, Elk Ridge, working at the New Horizon Mine. This plan is a qualified pension plan under Section 401(a) of the Internal Revenue Code of 1986, as amended. Benefits, which accrue under the plan, are based upon the employee's annual base salary as of November 15 of the previous year, their years of benefit service and the plan multiplier.

401(k) Plans. We offer one 401(k) plan to all employees. We contribute 1 percent of employee base salary for all non-bargaining employees.

We offer one 401(k) plan to all employees of Elk Ridge working at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions.

We offer one 401(k) plan to employees of Elk Ridge working at the New Horizon Mine and match 1 percent of bargaining employee contributions and contribute 1 percent of employee base salary for all non-bargaining employees.

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

NRECA Pension Restoration Plan and Executive Restoration Plan. We participate in the NRECA Pension Restoration Plan and the NRECA Executive Benefit Restoration Plan both of which are intended to provide a supplemental benefit to the defined benefit plan for an eligible group of highly compensated employees. Eligible employees include the Chief Executive Officer and any other employees that become eligible. The employees that currently participate in the NRECA Pension Restoration Plan are: Joel Bladow, Patrick Bridges, Micheal McInnes, Bradford Nebergall, Kenneth Reif and Barbara Walz. The employees that currently participate in the NRECA Executive Benefit Restoration Plan are: Ellen Connor, Jennifer Goss, and Barry Ingold. Eligibility is determined annually and is based on January 1 base salary that exceeds the limits of the defined benefit plan.

Perquisites and Other Benefits

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

- Company vehicle: the Chief Executive Officer and other executive officers are provided a company vehicle for both business and personal use. There are no restrictions on usage. These vehicles are considered compensation, which is grossed up for income taxes.

- Vacation: Executive officers with less than 20 years of service with us accrue vacation at the rate of five weeks per year. Upon completion of 20 years of service this accrual rate increases to six weeks per year. They may accrue up to a maximum of 1,040 hours of vacation.

Compensation Committee Report

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

Executive Committee Members:

Rick Gordon
Leo Brekel
Julie Kilty
Stuart Morgan
Matt M. Brown
Donald Keairns
Arthur W. Connell
William Mollenkopf
Timothy Rabon

Compensation Committee Interlocks and Insider Participation

As described above, the Executive Committee of our Board recommends the compensation for our Chief Executive Officer to the entire Board and the entire Board approves the compensation. The Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other employees other than himself. Rick Gordon, Leo Brekel, Julie Kilty, Stuart Morgan, Matt M. Brown, Donald Keairns, Arthur W. Connell, William Mollenkopf, and Timothy Rabon serve as members of the Executive Committee.

Other than as noted below, no member of the Executive Committee is, or previously was, an officer or employee of us. Mr. Gordon is our Chairman and President, Mr. Brekel is our Vice Chairman, Ms. Kilty is our Secretary, Mr. Morgan is our Treasurer, Mr. Brown is our Assistant Secretary and Mr. Keairns is our Assistant Secretary. All of the members of our Executive Committee are directors of our Members. Each of our Members has a wholesale electric service contract with us and we received revenue from each of our Members in excess of $120,000 in 2017.

Executive Compensation

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our Principal Executive Officer, Principal Financial Officer and our three other most highly paid executive officers (based on total compensation for 2017). The table also identifies the principal capacity in which each of these executives serves or served.

Name and Title	Year	Salary	Bonus	Change in pension value and nonqualified deferred compensation earnings	All other compensation(1)	Total
Micheal S. McInnes	2017	$ 790,072	$ —	$ 216,476	$ 37,344	$ 1,043,892
Chief Executive Officer	2016	728,462	—	160,748	34,767	923,977
	2015	680,771	—	— (2)	38,577	719,348
Patrick L. Bridges	2017	418,305	—	268,002	46,513	732,820
Senior VP/CFO	2016	405,936	—	170,074	136,300	712,310
	2015	401,413	—	240,449	49,718	691,580
Ellen Connor	2017	278,894	—	425,965	29,629	734,488
Senior VP, Organizational	2016	266,757	—	308,485	22,899	598,141
Services/CTO	2015	265,138	—	400,891	27,960	693,989
Bradford Nebergall	2017	383,244	—	209,686	44,587	637,517
Senior VP, Energy	2016	386,107	—	135,352	127,890	649,349
Management	2015	374,872	—	193,205	47,479	615,556
Barry Ingold	2017	347,869	—	234,329	21,813	604,011
Senior VP, Generation	2016	350,477	—	148,104	22,844	521,425
	2015	319,043	—	154,630	26,300	499,973

(1) Includes retention agreement payments, if applicable, personal use of auto which is grossed up to cover taxes, employer 401(k) contribution, group term life, and employer paid premium for medical and dental insurance.

(2) Mr. McInnes quasi-retired on April 10, 2015 from the RS Plan at which time the benefit calculation started over on April 11, 2015. Therefore the change in value of the plan from December 31, 2014 to December 31, 2015 was a negative $1,976,117.

Defined Benefit Plan

The following table lists the estimated values under the RS Plan and the pension restoration plans as of December 31, 2017. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits is limited to $270,000 effective January 1, 2017.

Name	Number of years Credited Service as of December 31, 2017	NRECA Retirement Security Plan Present Value of Accumulated Benefit as of December 31, 2017	Pension Restoration Plans Present Value of Accumulated Benefit as of December 31, 2017	Payments During 2017
Micheal S. McInnes	2 years, 6 months (1)	$ 217,070	$ 1,750,491	$ None
Patrick L. Bridges	10 years, 3 months	787,063	342,003	None
Ellen Connor	35 years, 10 months	2,220,731	22,867	None
Barry Ingold	13 years, 0 months	707,311	55,587	None
Bradford Nebergall	9 years, 3 months	708,587	258,389	None

(1) Mr. McInnes received quasi-retirement lump sum on April 10, 2015. On April 11, 2015, Mr. McInnes began accruing a new pension plan benefit. Number of years credited for NRECA Pension Restoration Plan is 33 years, 9 months.

There is a one year waiting period after commencement of employment before participants are eligible for the RS Plan. This waiting period is waived if the participant was previously eligible for the RS Plan at another participating employer.

The pension benefits indicated above are the estimated amounts payable by the plan, and they are not subject to any deduction for Social Security or other offset amounts. The participant's annual pension at his or her normal retirement date, currently age 62, is equal to the product of his or her years of benefit service multiplied by the average of his or her highest annual salary in five of the last ten years multiplied by 1.9 percent. The value listed in the table is the actual lump sum value payable to the employee if they had terminated employment on December 31, 2017.

Chief Executive Officer Pay Ratio

The 2017 compensation disclosure ratio of the median annual total compensation of all our employees to the annual total compensation of our Chief Executive Officer is as follows:

Category and Ratio	2017 Total Compensation (1)
Median annual total compensation of all employees (excluding Chief Executive Officer)	$ 125,329
Annual Total Compensation of Micheal S. McInnes, Chief Executive Officer	1,043,892
Ratio of the median annual total compensation of all employees to the annual total compensation of Micheal S. McInnes, Chief Executive Officer	1.0:8.3

(1) Includes change in pension value from 2016 to 2017.

In determining the median employee, a listing was prepared of all active employees of us and our subsidiaries as of December 31, 2017. We did not make any assumptions, adjustments, or estimates with respect to total compensation, and we did not annualize the compensation for any full-time employees that were not employed by us for all of 2017. We determined the compensation of our median employee by 1) utilizing the W-2 Box 5 wages for all active employees for 2017 and 2) ranking the annual total compensation of the employees, except the Chief Executive Officer, from lowest to highest. To determine if a material difference exists in the total compensation of the median employee compared to other employees when adding the change in pension value for the employee, we added this value to the median employee and to the three employees below and three employees above. After completing this evaluation of the seven employees, it was determined there was a material difference in the pension value of the years of benefit service of the seven employees. Therefore, we did change the median employee after adding the change in pension value to be the median employee of the above mentioned seven employees.

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

Our Chief Executive Officer Pay Ratio is a reasonable estimate calculated in a manner consistent with Item 402(u) of Regulation S-K. However, due to the flexibility afforded by Item 402(u) of Regulation S-K in calculating the Chief Executive Officer Pay Ratio, our Chief Executive Officer Pay Ratio may not be comparable to the Chief Executive Officer pay ratios presented by other companies.

Board of Directors Compensation

Chairman and President of the Board

The Chairman and President of the Board is compensated per Board policy as follows:

1) Director allowances are paid to the Chairman and President based on the requirement that the Chairman and President is required to participate in Tri-State activities or be available for consultation for 260 days per year. The allowance for each full or partial day is $625. The Chairman and President is also reimbursed for all out-of-pocket expenses incurred on our behalf.

2) The Chairman and President is assigned a company vehicle for business and personal use.

Board of Directors

The Board, excluding the Chairman and President, are compensated per Board policy as follows:

1) The allowance for attendance of a director at a regular or special meeting of the Board is $500 for each day of meeting.

2) The allowance for attendance of a director at any other meeting on Tri-State business is $500 for each day of meeting.

3) The allowance for travel time for directors going to and from the above meetings, where one or more days or a partial day of travel is required in addition to the day of the meeting, is $500 for each such day.

4) There is no allowance for telephone conference meetings.

5) Directors are reimbursed for transportation in connection with the foregoing meetings and functions at the published maximum IRS approved mileage rate for use of a personal vehicle, or for the actual commercial plane, bus, rail, and taxi fares incurred, including tax. Transportation by any other means is reimbursed at the equivalent rates for the use of a personal vehicle, or where appropriate, the commercial plane fare.

6) The allowance for meal and hotel expenses of a director incurred in connection with attendance at a regular, special, or committee meeting of the Board or other authorized meetings and functions is at the published maximum IRS allowable per diem rate.

Deferred Compensation Program

The Board, including the Chairman and President of the Board, are eligible to participate in the Directors' Elective Deferred Fees Plan established as a Rabbi Trust. This program allows for deferral of director's fees into an unfunded and unsecured plan under Section 409A of the Internal Revenue Code. Under this program, the funds are held in trust by Wells Fargo Bank and the funds are subject to claims by our creditors in the event of insolvency.

Board of Directors Compensation Table

The following table sets forth information concerning fees paid to the Board in 2017 for services rendered. Director fees are paid after submission of receipts by the Members to us. Amounts in the table reflect actual payments made in 2017. Directors are also reimbursed for expenses as described above.

Name	2017 Board Fees(1)
Robert Baca	$ 20,000
Robert Bledsoe	29,000
Leo Brekel	18,500
Matt M. Brown	23,000
Jerry Burnett	18,500
Tony Casados(4)	27,000
Richard Clifton	13,800
Arthur W. Connell(3)	33,500
Lucas Cordova Jr.	20,000
John "Jack" Finnerty(3)	25,500
Gary Fuchser	21,000
John Gavan(4)	11,500
Rick Gordon(2)	167,447
Jack Hammond	21,500
Ronald Hilkey	17,000
Ralph Hilyard	17,000
Donald L. Kaufmann	3,500
Donald Keairns	24,200
Hal Keeler	32,750
Julie Kilty	26,750
Kyle S. Martinez	9,500
Kohler McInnis	3,300
Thaine Michie(3)	25,500
William Mollenkopf	29,250
Christopher Morgan	23,000
Stuart Morgan	30,000
Richard Newman	22,500
Stanley Propp	22,000
Timothy Rabon	30,250
Steve M. Rendon	4,500
Gary Rinker	3,150
Claudio Romero	19,500
Peggy A. Ruble	2,000
Donald Russell	19,500
Brian Schlagel	22,000
Donald Schutz	17,000
Jack Sibold	20,500
Darryl Sullivan	23,100
Jerry Thompson(4)	9,000
Carl Trick II	19,000
Joseph Wheeling(4)	19,500
Donald Wolberg	20,500
Scott Wolfe	19,500
William Wright	21,000
Phillip Zochol	11,000

(1) Various board members have deferred some or all of their actual Board fee payments made in 2017 for a total of $101,150. Any deferred Board fees are not reflected in the above table.
(2) Includes personal use of auto allowance which is grossed up to cover taxes.
(3) Includes fees received for serving as a director of our subsidiary, Elk Ridge.
(4) Individual ceased serving on the Board prior to December 31, 2017.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not applicable

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

Because we are a cooperative, our Members own us. Each of our directors, as required by our Bylaws, is a general manager, director or trustee of the Member that it represents on our Board. Each of our Members has a wholesale electric service contract with us and we received revenue from each of our Members in excess of $120,000 in 2017.

Certain of our directors serve on the board of managers of Elk Ridge, a subsidiary of ours, and/or the board of directors of other entities in which we have ownership interests, including Trapper Mining. We have multiple contracts with Elk Ridge for the purchase of coal for our facilities. We purchased $64.9 million of coal from Elk Ridge in 2017, which was eliminated through financial consolidation. We purchased coal for the Yampa Project from Trapper Mining of $18.8 million in 2017.

Other than as described above, in 2017, we had no transactions with any related persons that exceeded $120,000 and there are currently no proposed transactions with any related persons that exceed $120,000.

Our Board has adopted a conflicts of interest policy that sets forth guidelines for the approval of any related party transaction and requires that our directors, senior management, and certain employees annually report and supplement as needed to the Chairman and President of the Board all personal and business relationships that could influence decisions related to our operation and management, as well as any relationships that could give the appearance of influencing such decisions.

Director Independence

Because we are an electric cooperative, our Members own us. Our Bylaws set forth the specific requirements regarding the composition of our Board. See “DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE –Directors” for a description of these requirements.

In addition to meeting the requirements set forth in our Bylaws, all directors satisfy the definition of director independence as prescribed by the NASDAQ Stock Market and otherwise meet all the requirements set forth in our Bylaws. Although we do not have any securities listed on the NASDAQ Stock Market, we have used its independence criteria to make this determination in accordance with applicable SEC rules.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for services provided by our independent registered accounting firm, Ernst & Young LLP, for the two most recent fiscal years.

	2017	2016
Audit Fees(1)	$ 777,000	$ 770,000
Audit-Related Fees(2)	2,000	22,500
Tax Fees(3)	35,000	34,625
All Other Fees(4)	—	—
Total	$ 814,000	$ 827,125

(1) Audit of annual financing statements and review of interim financial statements included in SEC filings and services rendered in connection with financings, including comfort letters, consents, and comment letters.
(2) Other audit-related services primarily related to assistance in evaluating the requirements of the Sarbanes-Oxley Act of 2002.
(3) Professional tax services including tax consulting and tax return compliance.
(4) All other fees.

For the two most recent fiscal years, other than those fees listed above, we did not pay Ernst & Young LLP any fees for any other products or services.

Pre-Approval Policy

All audit, tax, and other services to be performed by Ernst & Young LLP for us must be pre-approved by the Finance and Audit Committee. In the event that time does not allow for Finance and Audit Committee pre-approval of non-audit fees, non-audit service may be performed by Ernst & Young LLP if pre-approved by both the Chairman and the Vice-Chairman of the Finance and Audit Committee. The Finance and Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services. Pre-approval is granted usually at regularly scheduled meetings. During 2017 and 2016, all services performed by Ernst & Young LLP were pre-approved by the Finance and Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of Documents Filed as a Part of This Report.

1. Financial Statements
   See Index to Financial Statements under Part II, Item 8

2. Financial Statements Schedules
   Not Applicable

3. Exhibits

Exhibit Number	Description
3.1†	Amended and Restated Articles of Incorporation of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016, File No. 333-203560.)
4.1†	Indenture, dated effective as of December 15, 1999, between Tri-State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) Trustee, as supplemented by Supplemental Indenture No. 2, dated June 30, 2000, Supplemental Indenture No. 20, dated July 30, 2009, Supplemental Indenture No. 21, dated October 8, 2009, Supplemental Indenture No. 27, dated July 29, 2011, Supplemental Indenture No. 28, dated March 15, 2012, Supplemental Indenture No. 29, dated December 6, 2012, Supplemental Indenture No. 30, dated July 3, 2013, Supplemental Indenture No. 34, dated October 30, 2014 and Supplemental Indenture No. 38, dated November 21, 2014 (Filed as Exhibit 4.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.1.1†	Supplemental Master Mortgage Indenture No. 39, dated and effective as of May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.1.2	Supplemental Master Mortgage Indenture No. 40, dated and effective as of November 16, 2017, between Tri-State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) trustee
4.2†	Exchange and Registration Rights Agreement, dated October 30, 2014, between Tri-State Generation and Transmission Association, Inc. and Goldman, Sachs & Co. (Filed as Exhibit 4.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.3†	Form of Exchange Bond for 3.70% First Mortgage Bonds, Series 2014E-1, due 2024 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.4†	Form of Exchange Bond for 4.70% First Mortgage Bonds, Series 2014E-2, due 2044 (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
4.5†	Exchange and Registration Rights Agreement, dated May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc. and Wells Fargo Securities, LLC (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.6†	Form of Exchange Bond for 4.25% First Mortgage Bonds, Series 2016A, due 2046 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement, File No. 333-212006.)
4.7.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.7.2* Secured Promissory Note, dated January 10, 1989, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9028, in the original principal amount of $1,969,377

4.8.1* Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.8.2* Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9039, in the original principal amount of $821,815.11

4.8.3* Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9040, in the original principal amount of $32,224,821

4.9.1* Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.9.2* First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997

4.9.3* Secured Promissory Note, dated March 14, 1997, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9044, in the original amount of $15,600,000

4.9.4* Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999

4.9.5* Secured Promissory Note, dated January 26, 1999, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9046, in the original amount of $1,172,665.68

4.10.1* Master Loan Agreement, dated June 8, 2006, between Tri-State and CoBank, ACB

4.10.2* Amendment to Master Loan Agreement, dated June 8 2006, between Tri-State and CoBank, ACB related to Loan No. ML0303T5

4.10.3* Promissory Note, dated June 8, 2006, from Tri-State to CoBank, ACB, related to Loan No. ML0303T5, in the original amount of $70,000,000

4.11.1* Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB

4.11.2* Secured Promissory Note, dated December 6, 2012, from Tri-State to CoBank, ACB, related to Loan No. 002660317, in the original amount of $100,000,000

4.12.1* Unsecured Term Loan Agreement, dated June 10, 2013, between Tri-State and CoBank, ACB

4.12.2* Promissory Note, dated June 10, 2013, from Tri-State to CoBank, ACB, related to Loan No. 002713681, in the original amount of $71,000,000

4.13.1* Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB

4.13.2* Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan A 002847868, in the original amount of $68,345,000

4.13.3* Promissory Note, dated November 4, 2014, from Tri-State to CoBank, ACB, related to term loan B 002847716, in the original amount of $102,220,000

4.14.1* Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.14.2* Secured Promissory note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077

4.15.1* Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation

4.15.2* Secured Promissory Note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9078

4.16* Amended and Restated Bond, dated October 2, 2017, pursuant to the Trust Indenture, dated February 1, 2009, between Moffat County, Colorado and Wells Fargo, in the original amount of $46,800,000 related to Pollution Control Refunding Revenue Bonds, Series 2009B.

4.17.1* Notes, dated April 8, 2009, from Tri-State to various purchasers, relating to Series 2009C Note Purchase Agreement

4.17.2* Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement

4.17.3* Notes, dated December 12, 2017, from Tri-State to various purchasers, relating to 2017 Note Purchase Agreement

4.18.1* Note, dated October 21, 2003, from Springerville Unit 3 Holding to Wilmington Trust Company, relating to Tri-State 2003-Series A Pass Through Trust, in the original amount of $355,000,000, due in 2018

4.18.2* Note, dated October 21, 2003, from Springerville Unit 3 Holding to Wilmington Trust Company, relating to Tri-State 2003-Series B Pass Through Trust, in the original amount of $405,000,000, due in 2033

4.19.1* Security Agreement, dated March 25, 2011, from Elk Ridge Mining and Reclamation, LLC (formerly Western Fuels-Colorado, A Limited Liability Company) to Wells Fargo Equipment Finance, Inc.

4.19.2* Promissory Note, dated March 25, 2011, from Elk Ridge Mining and Reclamation, LLC (formerly Western Fuels-Colorado, A Limited Liability Company) to Wells Fargo Equipment Finance, Inc., in the original principal amount of $843,011

4.20.1* Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000

4.20.2* Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000

10.1† Second Amended and Restated Wholesale Power Contract for the Eastern Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.1 to the Registrant’s Form 8-K filed on September 28, 2017, File No. 333-212006.))

10.2† Wholesale Power Contract for the Western Interconnection, dated as of September 27, 2017, between Tri-State and Basin Electric Power Cooperative (Filed as Exhibit 10.2 to the Registrant’s Form 8-K filed on September 28, 2017, File No. 333-212006.)

10.3† Missouri Basin Power Project—Laramie River Electric Generating Station and Transmission System Participation Agreement, executed on various dates during the months of September, November and December, 1975, taking effect as of May 25, 1977, amongst Basin Electric Power Cooperative, Tri-State, City of Lincoln, Nebraska, Heartland Consumer Power District, Wyoming Municipal Power Agency, and Western Minnesota Municipal Power Agency, as amended by Amendment No. 1, dated as of March 15, 1977, Amendment No. 2, dated as of March 16, 1977, Amendment No. 3, dated as of August 1, 1982, Amendment 4, dated as of September 1, 1982, Amendment No. 5, dated as of May 2, 1983, Amendment No. 6, dated as of March 1, 1986, Amendment No.7, dated as of September 15, 1986, Amendment No. 8, dated as of June 10, 1997, Amendment No. 9, dated as of April 16, 1999, and Amendment No. 10, dated as of July 31, 2014 (Filed as Exhibit 10.2 to the Registrant’s Form S-4 Registration Statement, File No. 333-203560.)

10.4† Wholesale Electric Service Contract, dated November 1, 2001, between Tri-State and Delta-Montrose Electric Association (Filed as Exhibit 10.3 to the Registrant’s Form S-4 Registration Statement, File No. 333-203560.)

10.5† Wholesale Electric Service Contract, dated July 1, 2007, between Tri-State and Big Horn Rural Electric Company, together with a schedule identifying 41 other substantially identical Wholesale Electric Service Contracts (Filed as Exhibit 10.4 to the Registrant’s Form S-4 Registration Statement, File No. 333-203560.)

10.6† Participation Agreement, dated as of October 21, 2003, among Tri-State, as Construction Agent and as Lessee, Wells Fargo Delaware Trust Company, as Independent Manager, Springerville Unit 3 Holding LLC, as Owner Lessor, Springerville Unit 3 OP LLC, as Owner Participant, and Wilmington Trust Company, as Series A Pass Through Trustee and Series B Pass Through Trustee and as Indenture Trustee (Filed as Exhibit 10.5 to the Registrant’s Form S-4 Registration Statement, File No. 333-203560.)

10.7.1†	Supplemental Master Mortgage Indenture No. 23, dated as of June 8, 2010, between Wells Fargo Bank, National Association, as Trustee, and Tri-State in connection with Series 2010A Secured Obligations (Filed as Exhibit 10.6.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.7.2†	Supplemental Master Mortgage Indenture No. 24, dated as of October 8, 2010, between Wells Fargo Bank, National Association, as Trustee, and Tri-State in connection with reopening and amending of Series 2010A Secured Obligations (Filed as Exhibit 10.6.2 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.8†	Series 2009C Note Purchase Agreement, dated as of April 8, 2009, between Tri-State and various purchasers of the notes identified therein (Filed as Exhibit 10.7 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.9†	2014 Note Purchase Agreement, dated as of October 31, 2014, between Tri-State and various purchasers of the notes identified therein (Filed as Exhibit 10.8 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.10†	Credit Agreement, dated as of July 29, 2011, amongst Tri-State, as borrower, each lender from time to time party thereto, including Bank of America, N.A., as administrative agent, as amended by Amendment No. 1, dated as of November 20, 2013 and Amendment No. 2, dated as of October 17, 2014 (Filed as Exhibit 10.9 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.11†	Form of Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 13, 2016, File No. 333-203560.)
10.12**†	Director Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008 (Filed as Exhibit 10.10 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.13**†	Executive Benefit Restoration Plan, dated December 12, 2014 (Filed as Exhibit 10.18 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
10.14**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014 (Filed as Exhibit 10.19 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)
12.1	Statement re: Computation of Ratios
21.1	Subsidiaries of Tri-State Generation and Transmission Association, Inc.
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Micheal S. McInnes (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Patrick L. Bridges (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Micheal S. McInnes (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Patrick L. Bridges (Principal Financial Officer).
95	Mine Safety and Health Administration Safety Data.
101	XBRL Interactive Data File.

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* Pursuant to Item 601(b)(4)(iii) of Regulation S-K, this document(s) is not filed herewith. We hereby agree to furnish a copy to the SEC upon request.

** Management contract or compensatory plan arrangement.

† Incorporated herein by reference.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Date: March 9, 2018

By: /s/ MICHEAL S. MCINNES

Name: Micheal S. McInnes
Title: Chief Executive Officer

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, this report has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ MICHEAL S. MCINNES Micheal S. McInnes	Chief Executive Officer (principal executive officer)	March 9, 2018
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	March 9, 2018
/s/ DENNIS J. HRUBY Dennis J. Hruby	Senior Manager Controller (principal accounting officer)	March 9, 2018
/s/ RICK GORDON Rick Gordon	Chairman, President and Director	March 9, 2018
/s/ LEO BREKEL Leo Brekel	Director	March 9, 2018
/s/ JULIE KILTY Julie Kilty	Director	March 9, 2018
/s/ STUART MORGAN Stuart Morgan	Director	March 9, 2018
/s/ MATT M. BROWN Matt M. Brown	Director	March 9, 2018
/s/ DONALD KEAIRNS Donald Keairns	Director	March 9, 2018
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 9, 2018

/s/ WILLIAM MOLLENKOPF William Mollenkopf	Director	March 9, 2018
 Timothy Rabon	Director	
/s/ ROBERT BACA Robert Baca	Director	March 9, 2018
/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 9, 2018
/s/ JERRY BURNETT Jerry Burnett	Director	March 9, 2018
/s/ RICHARD CLIFTON Richard Clifton	Director	March 9, 2018
/s/ LUCAS CORDOVA, JR. Lucas Cordova, Jr.	Director	March 9, 2018
/s/ JOHN FINNERTY John Finnerty	Director	March 9, 2018
/s/ GARY FUCHSER Gary Fuchser	Director	March 9, 2018
 Jack Hammond	Director	
/s/ RONALD HILKEY Ronald Hilkey	Director	March 9, 2018
/s/ RALPH HILYARD Ralph Hilyard	Director	March 9, 2018
/s/ DONALD L. KAUFMAN Donald L. Kaufman	Director	March 9, 2018
/s/ HAL KEELER Hal Keeler	Director	March 9, 2018
/s/ KYLE S. MARTINEZ Kyle S. Martinez	Director	March 9, 2018

/s/ KOHLER MCINNIS Kohler McInnis	Director	March 9, 2018
/s/ THAINE MICHIE Thaine Michie	Director	March 9, 2018
/s/ CHRISTOPHER MORGAN Christopher Morgan	Director	March 9, 2018
/s/ RICHARD NEWMAN Richard Newman	Director	March 9, 2018
Stanley Propp	Director	
/s/ STEVE M. RENDON Steve M. Rendon	Director	March 9, 2018
/s/ CLAUDIO ROMERO Claudio Romero	Director	March 9, 2018
/s/ PEGGY A. RUBLE Peggy A. Ruble	Director	March 9, 2018
/s/ DONALD RUSSEL Donald Russell	Director	March 9, 2018
/s/ BRIAN SCHLAGEL Brian Schlagel	Director	March 9, 2018
/s/ DONALD SCHUTZ Donald Schutz	Director	March 9, 2018
/s/ JACK SIBOLD Jack Sibold	Director	March 9, 2018
/s/ CHARLES J. SOEHNER Charles J. Soehner	Director	March 9, 2018
/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 9, 2018
/s/ TRAVIS SULLIVAN Travis Sullivan	Director	March 9, 2018

/s/ CARL TRICK II Carl Trick II	Director	March 9, 2018
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 9, 2018
/s/ DONALD WOLBERG Donald Wolberg	Director	March 9, 2018
/s/ SCOTT WOLFE Scott Wolfe	Director	March 9, 2018
/s/ WILLIAM WRIGHT William Wright	Director	March 9, 2018
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 9, 2018

Appendix A

Calculation of Financial Ratios

Equity to Capitalization Ratio

Indenture ECR		**2017** *($ in thousands)*
Total Debt	$	2,912,883
Total Margins & Equities		1,003,056
Total Capitalization	$	**3,915,939**
Indenture ECR		**25.6%**

Debt Service Ratio

		Year Ended December 31, 2017 *($ in thousands)*
Net Margins Available for Debt Service		
Net Margins	$	61,656
Interest Expense		127,153
Amortization of debt discount or premium		2,195
Depreciation, depletion, obsolescence, amortization of property rights, etc.		139,051
Lease Expenses		66,232
Net Margins Available for Debt Service (NMADS)	$	396,287
Annual Debt Service Requirements		
Principal of all debt of the Association	$	68,703
Interest on all debt coming due		127,192
Amortization of Balloon Payments		60,067
Lease Payments		82,746
Annual Debt Service Requirement (ADSR)	$	338,708
Debt Service Ratio		**1.17**