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 period ended December 31, 2015

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. 333-203560

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

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

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 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 filer pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, the best of the Registrant's knowledge, if 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 or a smaller reporting company. See definitions of ''large accelerated filer,'' ''accelerated filer,'' and ''smaller reporting company'' in Rule 12b-2 of the Exchange Act. (Check one): Large Accelerated Filer ☐ Accelerated Filer ☐ Non-Accelerated Filer ☒ Smaller Reporting Company ☐

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.

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GLOSSARY

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

Abbreviations or Acronyms	Definition
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BART	best available retrofit technology
Basin	Basin Electric Cooperative Corporation
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
CoBank	CoBank, ACB
Colowyo Bonds	Coal Contract Receivable Collateralized Bonds
Colowyo Coal	Colowyo Coal Company L.P
COPUC	Colorado Public Utilities Commission
Craig Station	Craig Generating Station
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
DSR	Debt Service Ratio (as defined in our Master Indenture)
ECR	Equity to Capitalization Ratio (as defined in our Master Indenture)
EMS	Environmental Management System
EPA	Environmental Protection Agency
Escalante Station	Escalante Generating Station
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
Fitch	Fitch Rating Inc.
FPA	Federal Power Act, as amended
GAAP	accounting principles generally accepted in the United States
IRC	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
JMEC	Jemez Mountains Electric Cooperative, Inc.
kWh	kilowatt hour
LIBOR	London Interbank Offered Rate
LIFO	last-in, first-out
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
MATS	Mercury and Air Toxics Standard
MBPP	Missouri Basin Power Project
Members	our 44 member distribution systems
Moody’s	Moody’s Investors Services
MRO	Midwestern Reliability Organization
MRRE	Multi-Regional Registered Entity
MSMEC	Mora-San Miguel Electric Cooperative, Inc.
MW	megawatt
MWh	megawatt hour
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
NSR	New Source Review
OSMRE	Office of Surface Mining Reclamation and Enforcement
PCB	polychlorinated biphenyls
PPA	purchase power agreement
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 Ratings Services
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	sulfur dioxide
SPP	Southwest Power Pool
Springerville Partnership	Springerville Unit 3 Partnership LP
Springerville Unit 3	Springerville Generating Station Unit 3
STB	Surface Transportation Board
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.
WFC	Western Fuels-Colorado, A Limited Liability Company
WFW	Western Fuels-Wyoming, Inc.
XBRL	Extensible Business Reporting Language
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 major parts 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 Members, which, in turn, supply retail electric power to residential, commercial, industrial and agricultural customers in a service area with a population of approximately 1.5 million people.

We are owned entirely by our 44 Members. Forty 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 territory of our Members covers approximately 200,000 square miles and their customers include rural residences, farms and ranches, and large and small businesses and industries. 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.tristategt.org. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on 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, 2015, we employed 1,561 people, of which approximately 361 were subject to collective bargaining agreements. As of the date of this annual report on Form 10-K, 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 constitutes 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 and the cooperative's loan and security agreements.

Electric cooperatives generally include distribution cooperatives, such as the majority 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 facilities, long-term purchase contracts and forward, short-term and spot market 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 2,841 MWs, including 1,874 MWs from coal-fired base load facilities and 967 MWs from gas/oil-fired facilities. We purchase hydroelectric power under long-term purchase contracts which provide us with maximum available power of 583 MWs during the summer and 536 MWs during the winter. We purchase additional power on a long and short-term basis, including 249 MWs from other renewable energy resources, including wind, solar and small hydro. In 2015, we executed a 76 MW wind-based power purchase agreement and 55 MWs of solar-based power purchases agreements that are expected to achieve commercial operation in 2016 and 2017. 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. We have ownership or capacity interests in approximately 5,560 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 357 substations and switchyards. See "PROPERTIES" for a description of our generation 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 spot 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 agribusiness 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. 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.	Northern Rio Arriba Electric Cooperative, Inc.
Columbus Electric Cooperative, Inc.	Otero County Electric Cooperative, Inc.
Continental Divide Electric Cooperative, Inc.	Sierra Electric Cooperative, Inc.
Jemez Mountains Electric Cooperative, Inc.	Socorro Electric Cooperative, Inc.
Kit Carson Electric Cooperative, Inc.	Southwestern Electric Cooperative, Inc.
Mora-San Miguel Electric Cooperative, Inc.	Springer 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, Inc.
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 constitute approximately 95 percent of our revenue from Member sales in 2015) and extending through 2040 for the remaining two Members (Kit Carson Electric Cooperative, Inc. and Delta Montrose Electric Association which constitute approximately 5 percent of our revenue from Member sales in 2015), and 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 our Members, and obligates our Members 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. Our Members 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, 2015, 16 Members have enrolled in this program with capacity totaling approximately 79 MWs.

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). The following table shows our Members' aggregate coincident peak demand for the years 2011 through 2015 and the amount of energy that we supplied them:

Year	Members' Peak Demand (MW)	Amount of Energy Sold (MWh)
2015	2,753	15,780,670
2014	2,813	15,426,603
2013	2,666	15,313,487
2012	2,798	15,717,468
2011	2,654	15,421,227

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 the policy and procedures 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., was 13.1 percent of our Member revenue and 11 percent of our overall revenue, in 2015. No other Member exceeded 10 percent of our Member revenue or our overall revenue in 2015. 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.

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 territory extends throughout the state and encompasses suburban, rural, industrial, agricultural and mining areas. In Nebraska, our Members' service territory is comprised primarily of rural residential and farm customers in the western portion of the state. In Wyoming, our Members' service territory extends from the north central to the southeastern portion of the state and encompasses rural residential, agricultural and mining areas. In New Mexico, our Members' service territory extends throughout the northern, southern, central and western parts of the state, serving agricultural, rural residential, suburban, small commercial and mining customers. The diversity in customer bases, economic sectors, climate and weather patterns of the service territories creates balance within our system.

Customers. Our Members' sales of energy in 2014 (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	30.4 %	83.0 %
Large commercial	38.3	0.1
Small commercial	21.3	12.7
Irrigation	8.3	3.9
Other	1.7	0.3

From 2009 to 2014, 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 1.9 percent in energy sales. In 2014, which is the most recent year with data available to us, the 15 largest customers of our Members represented 18.8 percent of electric energy sales by our Members, although no single customer of our Members represented more than 5 percent of our total energy sales. These customers are primarily in the minerals extraction and transportation business, including natural gas, carbon dioxide and oil production.

Our Members' average number of customers per mile of energized line has been stable since 2008 at approximately five customers per mile. System densities of our Members in 2014 ranged from 1.2 customers per mile to 12.5 customers per mile.

Relationship with Members

Our Members operate their systems on a not-for-profit basis. We are a membership 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. 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."

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, and commodity prices.

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 territory 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 spot sale 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. This policy was last revised in May 2015. 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 14 percent in 2015 and 18 percent thereafter.

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and a demand rate. 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. Approved by our Board in September 2015 and effective January 1, 2016, our 2016 wholesale rate (A-39 rate) has an energy rate billed based upon a price per kWh of energy delivered and a demand rate 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 Friday, with the exception of six holidays. In 2015 and 2014, our wholesale rate (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 developed demand response and energy shaping products to compliment 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 a price per kWh of energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using the Member's coincident peak during our peak period in each monthly billing period during our summer peak period or the winter peak period. Three Members elected this TR-1 optional rate. In 2013, our A-37 rate design was in effect. The A-37 rate design had slightly lower seasonal average demand rates compared to our A-38 rate. In 2012, our wholesale rate schedule (A-36 rate) had an energy rate billed based upon a price per kWh, of energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using actual metered kilowatt usage in each monthly billing period during our summer peak period or our winter peak period.

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 cents/kWh sales for the years 2011 through 2015. The average Member cents/kWh sales 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 the Members in that given year.

Year	Average Member Cents/kWh Sales
2015	7.133
2014	7.140
2013	7.125
2012	6.789
2011	6.536

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) wholesale rates 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 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.” Electric cooperatives are not subject to rate regulation by FERC, under the FPA, 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 2014, which is the most recent year with data available to us, our largest Member sold 1.6 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 2015, 63 percent of our energy resources were provided by our generation and 37 percent by purchased power.

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 2,841 MWs, including 1,874 MWs from coal-fired base load facilities and 967 MWs from gas/oil-fired facilities. See “PROPERTIES” for a description of our various generating facilities.

Purchased Power

We supplement our capacity and energy requirements not supplied by our generating facilities through long-term purchase contracts, and forward, short-term and spot market energy purchases.

Our principal long-term power purchase contracts are with WAPA and Basin. 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 and municipal electric systems and certain other “preference” customers. WAPA markets and transmits the power to us under 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 (which terminate September 30, 2024). In January 2015, we entered into a new contract with WAPA relating to the Loveland Area Project which commences upon termination of the above referenced contract terminating September 30, 2024, and will run through September 2054. We also expect to enter into two new contracts related to Salt Lake City Area Integrated Projects which will extend the term of those existing contracts. The Loveland Area Project generally consists of generation and transmission facilities located in the Missouri River Basin. The Salt Lake City Area Integrated Projects consists of generation and transmission facilities located in the Colorado River Basin. The following table shows the maximum power available from these WAPA resources in the winter season (October-March) and the summer season

(April-September):

Resource:	Summer (MW)	Winter (MW)
Loveland Area Projects	349	285
Salt Lake City Area/Integrated Projects	234	251
Total	583	536

We utilize a portion of our purchases from Basin to supply power to our Nebraska Members, which are primarily located east of the electrical grid separation and are generally isolated from our generating facilities that are located west of the separation. We have a contract with Basin for a term ending December 31, 2050, to supply the electrical requirements of our Nebraska Members in excess of power supplied by WAPA. As of December 31, 2015, the approximate Nebraska Members' need from this resource was 314 MWs. We also purchase 225 MWs from Basin for use west of the electrical separation under a contract for a term ending in 2050.

In addition to long-term power purchase contracts, we purchase power on the open market. 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 when we have excess power available above our firm commitments to both Members and non-members. We also utilize spot market purchases during periods of generation outages. However, in order to minimize our exposure to such spot market purchases, our power supply arrangements with PSCO and the Salt River Project provide that our obligation to supply power may be reduced in proportion to a decrease in our power supply resources. 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 generation facilities.

Renewable Power Purchases

In addition to our contracts with WAPA for hydroelectric power purchases, we have entered into various renewable power purchase contracts, the largest of which are summarized in the table below.

Facility Name	Location	Counterparty	Primary Fuel	Facility Rating (MW)	Year of Commercial Operation		Year of Contract Expiration	
Alta Luna Solar	New Mexico	TPE Alta Luna, LLC	Solar	25	2016	(1)	2041	(2)
Carousel Wind Farm	Colorado	Carousel Wind Farm, LLC	Wind	150	2016	(1)	2041	(2)
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	(1)	2041	(2)
Twin Buttes II Wind	Colorado	Twin Buttes Wind II, LLC	Wind	76	2017	(1)	2042	(2)

(1) Anticipated Year of Commercial Operation
(2) Anticipated Year of Contract Expiration based upon anticipated Year of Commercial Operation

Other Generation Development

We continuously evaluate potential resources required to serve the long-term requirements of our Members. Over the past several years, 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. Through December 2015, we have incurred development costs of approximately $94 million, including the purchase of certain water rights and real estate interests, in connection with the Holcomb development. There have been several legal challenges to the development of Holcomb, including challenges to the Prevention of Significant Deterioration Permit and to the effectiveness of RUS consents to Sunflower's development contracts with us. We, along with Sunflower, continue to work on the legal challenges to the Prevention of Significant Deterioration Permit. However, our Board has not yet made a decision to proceed with construction of the project including us exercising our option to acquire the development rights. We have also acquired real estate interests and water rights for the Colorado Power Project located near Holly, Colorado. Through December 2015, we have incurred development costs of approximately $71 million, including 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 a Prevention of Significant Deterioration Permit for this development.

Power Sale Contracts

We have entered into various power sales contracts with other utilities, the largest of which are discussed below. We have two existing agreements with PSCO for the sale of contingent power. The agreements are on substantially similar terms. Under the first agreement, we have agreed to supply to PSCO 100 MWs of capacity through March 2017. Under the second agreement, we have agreed to supply to PSCO on an annual basis through March 2016, 25 MWs of power from April through September and 75 MWs of power from October through March. These contracts are contingent upon the availability of capacity from Craig Station Units 1, 2, and 3, and Laramie River Generating Station Units 2 and 3. We also have two agreements with PSCO for the output of the two gas turbines at Knutson Generating Station and one gas turbine at the Limon Generating Station for a total of 210 MWs in tolling capacity sales that expire in April 2016. We do not expect these four agreements discussed above with PSCO to be renewed. Additionally, we, through one of our wholly-owned subsidiaries, have an agreement with PSCO to sell 122 MWs in tolling capacity from the J.M. Shafer Generating Station that expires in June 2019. We also have an agreement with Salt River Project to provide 100 MWs of power contingent on the operation of Springerville Unit 3 that expires in August 2036.

Fuel Supply

Coal. We purchase coal under long-term contracts and in spot market transactions. The long-term arrangements provide price stability and the spot market transactions provide the flexibility to purchase coal when it is economically attractive to do so. 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 2017, respectively	800,000
Craig Station Unit 3	Colowyo Mine	2017	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	2019	400,000
San Juan Generating Station Unit 3	San Juan (underground) Mine	2017(1)	180,000
Springerville Unit 3	North Antelope Rochelle Mine	2021	1,250,000 to 1,500,000

(1) San Juan Generating Station Unit 3 is expected to be retired by December 31, 2017

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 generation 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 Rockies, 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 forward 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. The table below provides an overview of our water supply arrangements. Our generating facilities, however, are located in the West where demand for available water supplies is heavy, particularly in drought conditions. Litigation and disputes over water supplies are common and often protracted, which can lead to uncertainty regarding any user's rights to available water supplies. If we are 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 two separate water rights proceedings in the State of New Mexico that could impact the water rights for Escalante Station. The first proceeding is an adjudication of water rights associated with 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 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. The second proceeding is an application by the City of Gallup for a permit to appropriate ground water within the underground water basin near Gallup. The City of Gallup seeks to increase pumping of ground water from areas near the Escalante Station. We are involved in the case to assure that any new pumping does not adversely impact the ground water supplies for the Escalante Station. Court proceedings are underway to determine the outcome of the application. These water rights proceedings could have a negative impact on our water supplies for Escalante Station, requiring us to secure alternative water supplies (at a cost which would likely be higher than the cost of the water supplies currently being used).

We are also involved in a water rights proceeding in the State of Colorado that could impact the water rights of Burlington Generating Station. The 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. If successful, such relief could limit the availability of water to well users, including us, requiring us to secure alternative water supplies (at a cost which would likely be higher than the cost of the water supplies currently being used).

	Direct Flow Amount in Cubic Feet per Second (cfs)	Annual Appropriation (Acre Feet/Year)	Storage Amount (Acre Feet/Year)	Our Percentage
Surface Water Rights				
Craig Station Units 1 and 2	75.3		8,310	24
Craig Station Unit 3	45.9		2,500	100
Nucla Generating Station	61.1		400	100
Underground Water Rights				
Burlington Generating Station		39		100
Escalante Station		4,397		100
Knutson Generating Station		32		100
Pyramid Generating Station		1,055		100
Contract Rights				
Craig Generating Station Unit 3			7,000	100
J.M. Shafer Generating Station		1,110		100
Limon Generating Station			50	100
Rifle Generating Station			275	100
Springerville Generating Station		20,000		25

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 substantial costs to obtain licenses, permits and approvals from various federal, state and local agencies. For example, 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 and updated 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 fifteen 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, established national air quality standards for major pollutants, and required 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 sulfur dioxide (SO_2) and nitrogen oxides (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, 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 will impact coal-based generating facilities to a greater extent than others.

Our facilities are currently equipped with pollution controls that limit emissions of SO_2, NOx, and particulates below the Clean Air Act and permit requirements. 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 3 has an activated carbon injection system to control mercury emissions. Escalante Station also has an activated carbon injection systems 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 activated carbon injection system for controlling mercury emissions. Nucla Generating Station includes a Circulating Fluidized Bed with limestone for SO_2 removal and baghouses for particulate removal.

Basin and the Public Service Company of New Mexico, as the respective operators for the Laramie River Generating Station and the San Juan Generating Station, are responsible for environmental compliance and reporting for those facilities. 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, San Juan 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 generation 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 sulfur dioxide 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 sulfur dioxide 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 2044 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. In 2014, the EPA proposed emission limits and emission guidelines of carbon dioxide for existing generating facilities in a comprehensive proposed rule referred to as the ''Clean Power Plan.'' On August 3, 2015, the EPA issued a pre-publication version of a final rule regarding emissions of carbon dioxide from certain fossil fuel-fired electric generating units. On October 23, 2015, the final rule was published in the Federal Register. The Clean Power Plan establishes guidelines for states to develop plans to limit emissions of carbon dioxide from existing units. Emissions of carbon dioxide from our plants totaled approximately 14.1 million short tons in 2014. The goal of the rule is a reduction in carbon dioxide emissions from 2005 levels of 32 percent nationwide by 2030 and specifies interim emission rates phasing in between 2022 and 2029. At this time it is not possible to understand how we will be impacted (financially or operationally) in each state, as that information will be developed in state specific plans. Under the final rule, states are required to submit a final compliance plan, or an initial plan with an extension request, to the EPA, by September 2016, or no later than September 2018 with an approved extension. However, the Supreme Court issued a stay of the Clean Power Plan on February 9, 2016, as such, the 2016 date is delayed and the other dates are most likely to be delayed. Once approved, states must implement their plan to ensure power plants achieve the interim carbon dioxide emissions performance goals.

The final state goals for carbon dioxide emissions per MWh in year 2030 and beyond under the Clean Power Plan for the five states where we would be impacted are as follows: Arizona—1,031 lb/MWh; Colorado—1,174 lb/MWh; Nebraska—1,296 lb/MWh; New Mexico—1,146 lb/MWh; and Wyoming—1,299 lb/MWh. Each of these goals is substantially below the carbon dioxide emission rate of a well-designed coal-fired unit and assumes increased reliance on a combination of natural gas-fired and renewable energy sources, with coal-fired generation being dispatched less often or curtailed entirely. The EPA also proposed a federal plan that would be implemented should states fail to submit acceptable plans. We submitted comments on the proposed federal plan, which were due on January 21, 2016.

The Clean Power Plan is the most complex and wide-ranging regulation under the Clean Air Act and litigation challenging the final rule is ongoing. We, along with 27 states, including Arizona, Colorado, Nebraska and Wyoming, other utilities and national trade organizations, have filed petitions for review of the Clean Power Plan with the D.C. Circuit Court of Appeals. We, along with 24 states, other utilities and national trade organizations, also filed motions to stay the Clean Power Plan with the D.C. Circuit Court of Appeals. On January 21, 2016, the D.C. Circuit Court of Appeals denied the motions to stay the Clean Power Plan, but ordered an expedited briefing schedule and scheduled oral arguments for June 2, 2016. We, along with 27 states, including Arizona, Colorado, Nebraska and Wyoming, other utilities and national trade organizations, filed applications for immediate stay of the Clean Power Plan with the United States Supreme Court. On February 9, 2016, the Supreme Court stayed the Clean Power Plan pending judicial review. The impacts of the final rule and any challenges cannot be determined at this time; however, 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.

EPA also issued a final NSPS for new and modified units which establishes carbon dioxide emission standards for plants built in the future. This NSPS does not create emission standards for Holcomb, but states that if the plant moves forward, EPA will create a separate rule for Holcomb due to the fact that it is so far along in the process. We, along with 25 states, other utilities and national trade organizations, have filed petitions for review of the NSPS with the D.C. Circuit Court of Appeals.

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, with a compliance deadline in April 2015. We were among the parties that legally challenged the MACT rule, but the rule was upheld by the D.C. Circuit Court of Appeals in April 2014. The Supreme Court agreed to review a narrow provision that focuses on whether the EPA reasonably considered costs in developing the MATS, and oral arguments in the case were heard on March 25, 2015. On

June 29, 2015, the Supreme Court ruled that the EPA acted improperly when it did not consider the cost of regulation in determining that it was "appropriate and necessary" to issue the MATS rule. The Supreme Court instructed the D.C. Circuit Court of Appeals to determine whether the rule should remain in place while the EPA reconsiders its "appropriate and necessary" determination. On December 15, 2015, the D.C. Circuit Court of Appeals remanded the proceeding to EPA without vacatur of the MATS rule. The EPA is on track to issue a final supplemental finding by April 15, 2016. We are in full compliance with the rule's emission limits, which required new emission controls on Craig Station Unit 3, Springerville Unit 3, Escalante Station and Laramie River Generating Station. The Colorado Department of Public Health and Environment approved our request to extend the MATS hydrochloric acid mist compliance date to April 16, 2016 for the Nucla Generating Station. Nucla Generating Station currently meets all other compliance aspects of the Mercury and Air Toxics Standards rule. The Arizona Department of Environmental Quality approved TEP's request to extend the MATS mercury compliance date to April 16, 2016 for Springville Unit 3 and TEP subsequently installed an activated carbon injection system for controlling mercury emissions at Springerville Unit 3.

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 NSR 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 ambient air quality standard for ozone from 75 parts per billion (ppb) to 70 ppb. Currently, J.M. Shafer Generating Station and Knutson Generating Station are our only generation facilities that are located in an ozone nonattainment area. It is not known whether the more stringent ozone standard may designate new areas as nonattainment and create more difficult permitting and operation conditions for additional generation facilities. Implementation of an ozone standard at 70 ppb will prove challenging because of the significance of "background" concentrations of ozone, which can be increased by several factors that yield particularly great influence in the western United States. Such factors include interstate and international transport, biogenic and wildfire emissions, and greater solar radiation at higher elevations.

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 ongoing.

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 include 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 told 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 will result in the installation of selective catalytic reduction on Craig Station Unit 2 no later than December 31, 2017. We estimate our cost of such project is approximately $42 million. The existing, approved SIP allowed for less stringent emissions limit on Craig Station Units 1 and 3, therefore significantly limiting the amount of additional controls required on those units. The Wild Earth 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 is a settlement agreement that commits us to a NOx emission rate limit for Craig Station Unit 1 that will require installation of selective catalytic reduction by August 31, 2021, at an estimated cost to us of approximately $42 million. The legislature of Colorado approved the new rule and delivered it to the EPA for review. In the case of each Craig Station unit, compliance involves capital and operational expenditures for NOx controls.

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 sulfur dioxide 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 other 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 is under administrative and legal challenges.

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 used by utilities in the event they have excess emissions during a startup, shutdown or malfunction events. 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 make SIP submissions to rectify the specifically identified deficiencies in their respective SIPs. Colorado recently 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. We are working with state environmental agencies to address changes to SIPs in each of the other noted states. We cannot predict the outcome of these proceedings at this time.

Water Quality

The Clean Water Act. The Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System permit program. At the present time, we have the required permits under the program for all of our electric 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 was published on November 3, 2015, with an effective date of January 4, 2016. It appears that the rule will have 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 anticipated to be minor as the facilities operate closed cycle cooling systems minimizing impingement and entrainment.

In April 2014, the EPA and the U.S. Army Corps of Engineers proposed an expansion of regulatory authority under the Clean Water Act through broadening the definition of a "Water of the United States." 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 "Waters of the United States" was announced in late May 2015 and published in the Federal Register on June 29, 2015. However, there is currently a nationwide stay issued by the United States Court of Appeals for the Sixth Circuit that is in effect as of October 9, 2015. Currently, we are continuing to review the rule to assess impacts and determine appropriate next steps.

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 waste 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 a designated landfill. The mine-fill and landfills are regulated by state environmental agencies and all required permits are in place. The EPA in 2010 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. Pursuant to litigation, 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 costs relating to the management of such by-products to be approximately $10 million. We are meeting all initial compliance obligations that became effective on October 19, 2015.

Renewable Portfolio Standards. Colorado law requires each electric cooperative to obtain at least 6 percent and 10 percent of its 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.

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; 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 Supreme Court.

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 Office of Surface Mining and state mine reclamation regulators to develop a better understanding of mine placement practices for coal ash. The Office of Surface Mining may in 2016 issue a proposed rulemaking establishing requirements and standards that apply when coal ash is used during reclamation at surface coal mining operations. Until these rules are promulgated, we cannot determine what, if any, controls we may be required to implement to comply with the regulation.

Mine Plan Approval. Colowyo Coal is expected to modify and expand operations to access coal reserves for future production as current mining plans are completed and land is reclaimed. Colowyo Coal received approval from Colorado state authorities with primacy to implement the federal mining permit program. Before the permitted operations may proceed, OSMRE must complete a mine plan review of the proposed modification and ensure compliance with applicable federal laws, including the National Environmental Policy Act. Then OSMRE must obtain approval of the modification from the Department of Interior, Assistant Secretary for Land and Minerals Management. The Department of Interior's January 15, 2016 pause on new federal coal leasing expressly excludes mine plan reviews by OSMRE and lease modifications under certain acre thresholds. The leases Colowyo Coal holds for continued development are not subject to the pause.

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. The EPA is expected to release a proposed rulemaking for more strict controls of PCBs in June of 2016. Until that rule is proposed it is not possible to estimate impacts to our operations.

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 electric transmission project. Of the several hundred species involved in the litigation settlement, we estimate that approximately 30 have the potential to affect our assets. 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 Endanger Species Act, in large part on the basis of federal land management agency-based conservation plans. In 2016, the U.S. Fish and Wildlife Service may issue a 4(d) rule for the gunnison sage-grouse. The listing of the lesser prairie-chicken as a threatened species was vacated in 2015 by a court for the western district of Texas. We are monitoring each of these issues as they develop over time.

TRANSMISSION

We have ownership or capacity interests in approximately 5,560 miles of high-voltage transmission lines and own or have major equipment ownership in approximately 357 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, Public Service Company of New Mexico and Deseret Generation & Transmission Cooperative. The majority of our transmission facilities operate as part of the Western Interconnection, an interconnected transmission grid which serves the western portion of the United States and Canada. 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 the transmission infrastructure in our service area and participate in many joint projects with other transmission owners within the interconnected grid. We believe these additions insure we can access and deliver into the Eastern and Western Interconnection marketplaces.

On June 3, 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. 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 processes are expected to begin during the first quarter of 2016. 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.

FERC

The FPA authorizes FERC to oversee the wholesale sale 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 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 proposed revised Board policy is consistent with the provisions of PURPA and the implementing regulations of FERC. The proposed 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. FERC has approved similar mechanisms in the past. In March 2016, our Board adopted the revised Board policy. We are also 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 an open access transmission tariff. 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.

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, 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 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 generation 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 also has 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 generation 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 MREE program is to streamline compliance and enforcement efforts for entities registered in multiple regions.

In 2015, we were audited by WECC and are scheduled for a future compliance audit in 2018 as part of a three-year audit cycle. While some violations were cited from the 2015 audit, and in each of the previous audits conducted in 2009, 2011 and 2012, 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.

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, and we may also be subject to new legislation or regulation, including legislation or regulation relating to greenhouse gas emissions or renewable or clean energy standards. 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. Without taking into account the Clean Power Plan, we expect that we will spend an additional $300 million through 2020 in efforts to maintain compliance. Currently, our existing generating facilities generate approximately 63 percent of our energy resources. 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 carbon dioxide 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 creates state goals, which are to be reached through measures inside and outside of the electric power generation and transmission industry. We are analyzing the potential impact of this final rule. The magnitude of the impact on our existing generating facilities is yet to be determined and will depend on the implementation of state specific plans by each of the states in which we have affected assets. States are to have plans, including regulations, in place in 2017 or 2018. However, with the United States Supreme Court's stay of the Clean Power Plan these dates are most likely to be delayed. EPA's final rule establishes an implementation date of 2022 and a compliance date of 2030. The impacts of the final rule and any challenges cannot be determined at this time; however, 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 44 Members. In March 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the COPUC alleging that our A-37 rate design was unjust and unreasonable. In December 2015, we and three Colorado Members filed a joint motion to withdraw the complaint and dismiss the proceeding. The joint motion was approved by the administrative law judge in January 2016.

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 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. Some of our New Mexico Members filed for such review in 2012 and 2013. The procedural schedule related to such rate reviews by the NMPRC are 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.''

We have a substantial amount of indebtedness and we expect this amount to increase.

As of December 31, 2015, we had total debt outstanding of approximately $3.4 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 generation and transmission facilities to supply the current and projected electricity requirements of our Members and to meet our other long-term electricity supply obligations. Additionally, we expect to incur substantial indebtedness in the future and we forecast that we will have approximately $3.8 billion of total debt outstanding in 2020. 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 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. 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 generation and transmission facilities to meet our Members' demands, which may require substantial additional capital expenditures which will significantly 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 generation and transmission facilities to serve our Members and long-term purchases of power from generation facilities owned by others or new generation facilities that may be developed by others. Without taking into account the Clean Power Plan, in the years 2016 through 2020, we estimate that we may invest approximately $1.4 billion in new facilities and upgrades to our existing facilities, including, but not limited to, investment in new generating facilities and transmission improvements, upgrades to our existing generating facilities and transmission facilities and investments in our coal mining facilities. We expect to incur significant indebtedness in connection with this capital expenditure program. Without taking into account the Clean Power Plan, beginning in year 2020, we estimate that we may need to invest substantial amounts to develop or lease additional generating capacity, and we may also need to invest substantial amounts for new transmission facilities and improvements to our existing transmission facilities. 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; and
- regulatory changes, such as regulation of carbon dioxide 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 resulting in a significant 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 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 capital for construction of new generation and transmission facilities and as a significant source of liquidity for capital expenditures not satisfied by cash flow generated from operations. Without taking into account the Clean Power Plan, in the years 2016 through 2020, we estimate that we may invest approximately $1.4 billion in new facilities and upgrades to our existing facilities which will require us to take on significant 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 generation and transmission facilities and to construct future generation 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, 2015, we had $523 million in variable rate debt. The interest rates on this debt could increase. The interest rates could also increase if an unrelated third-party associated with the debt, such as a remarketing agent or liquidity provider, displayed financial problems.

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 2014 data, industrial and large commercial customers account for approximately 38 percent of our Members' energy sales. A large percentage of these sales are in energy production, extraction and transportation, particularly in our forecasted load growth. The 15 largest customers of our Members, a substantial percentage of which are in energy production, extraction and transportation, total approximately 18.8 percent of the aggregate retail electric energy sales of our Members, based on the same 2014 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.

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 contract with us. In 2015, approximately 90 percent of our revenues from electric sales was 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. 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.

Changes in fuel prices could have an adverse effect on our cost of electric service.

We are exposed to the risk of changing prices for fuels, including coal, natural gas and oil. We have made certain arrangements to mitigate our expenses to fuel prices; however, these arrangements do not cover all of our risk exposure to increases in the prices of fuels. Therefore, increases in fuel prices could significantly increase the cost of electric service we provide to our Members and affect their ability to perform their contractual obligations to 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.

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 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, resulting in under recovery of our fixed costs. 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 value 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.

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 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. Generally, we serve our Members in rural territories that are less attractive to competitors.

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 generation 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 generation 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 generation 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 generation 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 generation and new and existing transmission facilities.

Our existing facilities require ongoing capital expenditures in order to maintain efficient and reliable operations. Many of our 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. While we do not currently have a generation plant under construction, we continually employ best operational and maintenance practices at our existing facilities.

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.

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 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 electric generating facilities.

Our performance depends on the successful operation of our electric generating facilities. Operating electric 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 electric generating facilities could lead to higher costs because we may be required to purchase power in volatile spot electric power markets. A decrease or elimination of revenues from electric power produced by our electric 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 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. In response to the increase in litigation on these types of claims, we have increased our liability insurance coverage. 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.

Renewable Portfolio Standards may increase our costs of operation and affect the utilization of current generation facilities.

Colorado and New Mexico have each enacted a RPS that establishes minimum amounts of electric energy (or an equivalent amount of renewable energy credits) that our Members are required to obtain from renewable sources or that we are required to provide to our Colorado Members from renewable sources. Colorado law requires each electric cooperative to obtain at least 6 percent and 10 percent of its energy requirements from renewable sources by year end 2015 and 2020, respectively. Colorado law was amended in 2013 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 increases 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. Neither we nor our Members are subject to an RPS in any other state.

We have executed approximately 368 MW of wind-based power purchase agreements and 85 MW of solar-based power purchases as a part of our plan to meet these RPS requirements. Our access to these new renewable resources has been secured at what we believe are reasonable prices due to the federal Production Tax Credit and Investment Tax Credit and advances in wind technology that have led to improvements in capacity factors. Integration of these intermittent power sources into our overall generation portfolio remains a concern, but we believe solutions will be developed that are reasonably cost effective.

If we cannot obtain the required percentages of energy from renewable resources to satisfy the RPS requirements, we will need to purchase an equivalent amount of renewable energy credits to meet the energy shortfall at market price from the secondary market, the prices of which may be higher than our own generation costs.

An additional consequence of the Colorado and New Mexico RPS is the strain imposed on the regional transmission system by the increasing capacity of intermittent generation facilities integrated, interconnected and planned to be interconnected with the transmission grid. The addition of major new wind projects will likely require accompanying transmission projects as much of the latent capacity in the system has been exhausted.

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 2015, purchased power provided approximately 37 percent of our energy requirements. These purchases consist of a combination of purchases under long-term contracts and market purchases of electric power in the spot markets. 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 spot 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 spot market purchases exposes us to increases in electric power prices.

Our long-term power purchase contracts include contracts with WAPA and Basin, consisting of approximately 15.2 percent and 12.9 percent, respectively, of our Member sales in 2015. 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 would have an adverse effect on our 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 interest 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	427	102	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
San Juan Generating Station Unit 3	New Mexico	8.2	Coal	488	40	1979
Gas/Oil						
Burlington Generating Station	Colorado	100.0	Oil	100	100	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	85	85	1986
J.M. Shafer Generating Station	Colorado	100.0	Gas	272	272	1994
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, 1,303 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 have capacities of 427 MWs and 428 MWs, respectively, 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 653 MWs.

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 Missouri Basin Power Project, 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 coal-fired, 1,578 MW 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. 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.

San Juan Generating Station Unit 3. San Juan Generating Station is a four unit, 1,600 MW, coal-fired electric generating facility located in the Four Corners area of New Mexico. We own an 8.2 percent interest in San Juan Unit 3, which has a capacity of 488 MWs. Our total share of San Juan Unit 3's capacity is approximately 40 MWs. Public Service Company of New Mexico, the New Mexico Environment Department and the EPA have agreed to pursue a plan to comply with federal visibility rules for the San Juan Generating Station. The plan would include the retirement of two units by the end of 2017. We expect that San Juan Generating Station Units 2 and 3 will be retired by December 31, 2017. We have executed a suite of agreements with the other eight owners of the San Juan Generating Station and PNMR Development and Management Corporation, which upon satisfaction of certain conditions will become effective and under which, among other things, we will exit active participation in station operations upon retirement of San Juan Unit 3 at the end of 2017. On January 31, 2016, some of these agreements became effective including the San Juan Project Restructuring Agreement.

Burlington Generating Station. Burlington Generating Station consists of two 50 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. Knutson Generating Station is wholly owned and operated by us. This facility is under contract to PSCO under a tolling arrangement through April 2016, which is an arrangement whereby the purchaser provides its own natural gas for generation of electricity.

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. Limon Generating Station is wholly owned and operated by us. One of the two units is under contract to PSCO under a tolling arrangement through April 2016.

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 85 MW, natural gas fired combined 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.

J.M. Shafer Generating Station. J.M. Shafer Generating Station is a combined cycle, 272 MW, natural gas-fired 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 the balance of the output is sold to us under a separate tolling agreement through June 2019. Our interest in the tolling agreement, as purchaser, is subject to the lien of our Master Indenture, but J.M. Shafer Generating Station is not subject to the lien of our Master Indenture.

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 and was installed in 1994.

Transmission

As of December 31, 2015, we own, lease, or have undivided percentage interest in transmission lines as described in the following table:

Voltage	Miles
69 kV	49 miles
115 kV	3,104 miles
138 kV	184 miles
230 kV	1,001 miles
345 kV	1,220 miles
Total	5,558 miles

We are an ownership participant in the Missouri Basin Power Project (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 357 substations and switchyards. All of our interest 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	Colorado	100
Trapper Mine(1)	Colorado	26.57
Dry Fork Mine(2)	Wyoming	27
Fort Union Mine(3)	Wyoming	50

(1) Trapper Mine is owned by Trapper Mining. We, along with certain participants, in the Yampa Project own Trapper Mining.
(2) Dry Fork Mine is owned by WFW. We own approximately 27 percent of the dedicated reserves.
(3) 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 new A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from all 44 of our Members by approximately 4.9 percent, with revenues from our 12 New Mexico Members increasing by approximately 6.7 percent. 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. We intend to pursue our federal challenge to the actions of the NMPRC. Also, on January 25, 2013, we made an additional filing at the NMPRC seeking interim rate recovery from our New Mexico Members during the pendency of the NMPRC proceedings on the original rate filing. The NMPRC denied the filing on March 13, 2013. We appealed that denial to the New Mexico Supreme Court. On April 6, 2015, the Court vacated the NMPRC denial of our interim rate recovery filing and remanded the case to the NMPRC for any proceedings that may be necessary to comply with the Court's order. On June 25, 2013, we filed to withdraw the 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 new A-38 wholesale rate which was scheduled to become effective on January 1, 2014. 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 (unless terminated earlier as provided in the preliminary mediation agreement) 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 the 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 2015 and 2014, the overall revenue impact of the New Mexico Members paying a lower rate was approximately $10.7 million and $16.4 million, respectively. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 wholesale rate, or the A-39 rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate became effective on January 1, 2016 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 7, 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.

COPUC Proceeding. On March 4, 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the COPUC alleging that our A-37 rate design was unjust and unreasonable. On April 4, 2013, we filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over our wholesale rates. The COPUC assigned the matter to an administrative law judge. The judge bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board, and secondly to hear the facts in the case depending on jurisdiction. The administrative law judge conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the administrative law judge's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the administrative law judge's decision and remanded the case to the administrative law judge to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The administrative law judge entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate. On December 28, 2015, we and the three Colorado Members filed a joint motion with the COPUC to withdraw the complaint and dismiss the proceeding. On January 19, 2016, the administrative law judge granted our joint motion to withdraw the complaint, dismiss the proceeding with prejudice and close the proceeding. The administrative law judge's order has become effective by operation of law.

Las Conchas Fire. In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five days in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, comprised 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 the 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. These cases are State Farm Fire and Casualty Company, et. al. v. Jemez Mountains Electric Cooperative, Inc., et. al. (amended complaint filed March 6, 2014); 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); United Services Automobile Association, et. al. v. Jemez Mountains Electric Cooperative, Inc. (amended complaint filed March 6, 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 are also jointly liable for any negligence by JMEC under joint venture and alter ego theories. On June 16, 2014, we filed multiple motions for summary judgment including for plaintiffs' claims related to nuisance, trespass, negligence per se, independent duty, joint venture and alter ego. On December 29, 2014, we received a demand letter from the U.S. Department of Justice for costs incurred as a result of the fire, also alleging the joint venture theory. JMEC has settled with 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. Settlement demands were received from plaintiffs Jemez Pueblo and Pueblo de Cochiti claiming damages in the amount of approximately $34.4 million and $23.9 million, respectively, focusing mainly on damages arising from flooding subsequent to the fire. On March 9, 2015, the district court granted our motions for summary judgment related to nuisance, trespass, negligence per se, and alter ego, but denied our motions related to independent duty and joint venture. On March 17, 2015, we filed an application for interlocutory appeal with the New Mexico Court of Appeals related to the district court's denial of our motions for summary judgment for plaintiffs' claims related to independent duty and joint venture. The New Mexico Court of Appeals denied our application for interlocutory appeal on May 27, 2015. A jury trial commenced on September 28, 2015. 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. On November 11, 2015, we filed a request with the district court to certify for interlocutory appeal certain issues regarding our duty under a negligence claim, which was denied by the district court in January 2016. Three or four separate trials will occur in the second half of 2016 and first quarter of 2017 to determine the amount of damages. We maintain $100 million in liability insurance coverage for this matter. Although we cannot predict the outcome of these matters 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.

Tres Lagunas Fire. In May 2013, near the Village of Pecos, New Mexico, a wildfire known as the Tres Lagunas Fire was ignited and subsequently destroyed timber on thousands of acres and burned for approximately three weeks. On March 25, 2014, a lawsuit was filed by David Old d/b/a Old Wood, The Viveash Ranch, and River Bend Ranch, LLC, against our Member, MSMEC, in the First Judicial District Court for the County of Santa Fe, New Mexico. In the complaint, plaintiffs allege that the Tres Lagunas Fire resulted from wind blowing a portion of a dead standing tree into an electric distribution power line owned and operated by MSMEC. On November 6, 2015, plaintiffs filed a motion to amend their complaint and include the addition of us as a defendant. The district court approved the motion to amend on November 20, 2015 and plaintiffs' first amended complaint was filed. Plaintiffs assert claims of negligence, violations of New Mexico's Unfair Practices Act, and strict liability. On December 21, 2015, we filed a motion to dismiss the New Mexico's Unfair Practices Act and strict liability claims and, additionally, filed our answer and 12-person jury demand. In 2014, we renewed our coverage and now maintain $200 million in liability insurance coverage for this matter. Although we cannot predict the outcome of this matter at this point in time, we do not expect it 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 two separate water rights proceedings in the State of New Mexico that could impact the water rights for Escalante Station. The first proceeding is an adjudication of water rights associated with Bluewater Toltec Area to determine the past, present and future use of water rights of the Pueblos of Acoma and Laguna. The second proceeding is an application by the City of Gallup for a permit to appropriate ground water within the underground water basin near Gallup. We are also involved in a water rights proceeding in the State of Colorado that could impact the water rights of Burlington 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 a summary of our consolidated financial data as of and for the years indicated. This summary 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,				
	2015	2014	2013	2012	2011
Selected Income Statement Data					
Operating revenues	$ 1,335,448	$ 1,395,091	$ 1,341,163	$ 1,291,832	$ 1,184,431
Operating expenses	(1,157,479)	(1,213,214)	(1,152,575)	(1,125,617)	(1,025,676)
Operating margins	177,969	181,877	188,588	166,215	158,755
Interest expense	(142,570)	(142,357)	(149,463)	(151,905)	(155,022)
Net margins attributable to the Association	53,413	64,236	72,912	52,795	69,934

	As of December 31,				
	2015	2014	2013	2012	2011
Balance Sheet Data:					
Total assets	$ 4,823,047	$ 4,654,136	$ 4,692,584	$ 4,561,680	$ 4,572,660
Electric plant, in service, less accumulated depreciation	3,245,786	3,064,063	2,941,860	2,926,700	2,819,499
Construction work in progress	216,279	206,097	231,374	152,355	183,178
Long-term debt	3,273,538	3,145,246	3,069,218	3,049,481	3,093,839
Patronage capital equity	952,082	908,669	865,379	802,467	759,672
Accumulated other comprehensive income (loss)	589	(828)	3,335	3,415	3,663
Noncontrolling interest	108,757	109,302	110,740	113,027	116,120
Total capitalization	$ 4,334,966	$ 4,162,389	$ 4,048,672	$ 3,968,390	$ 3,973,294

	For the years ended December 31,				
	2015	2014	2013	2012	2011
Other Data					
Ratio of Earnings to Fixed Charges	1.25	1.32	1.37	1.22	1.33

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 44 Members that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in the region pursuant to long-term contracts and spot sale arrangements. Our Members provide retail electric service to rural residences, farms and ranches, cities, towns and suburban communities, as well as large and small businesses and industries. In 2015, our Members served approximately 626,000 retail electric meters over a 200,000 square-mile area with a population of approximately 1.5 million people. In 2015, we sold 17.8 million MWhs, of which 89 percent was to Members. Total revenue from electric sales was $1.2 billion for 2015, of which 90 percent was from Member sales.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constitute approximately 95 percent of our revenue from Member sales in 2015) and extending through 2040 for the remaining two Members (Kit Carson Electric Cooperative, Inc., and Delta Montrose Electric Association, which constitute approximately 5 percent of our revenue from Member sales in 2015), and subject to automatic extension thereafter until either party provides at least a two year 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, 2015, 16 Members have enrolled in this program with capacity totaling approximately 79 MWs.

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 spot 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 Bylaws were amended in 2015 to provide the Board discretion on order of retirement. As of December 31, 2015, patronage capital equity was $952.1 million.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating facilities, long-term purchase contracts, and forward; short-term and spot market energy purchases. We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating facilities. 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 a long-term purchase contract with Basin, the electric power needs of our Members in the state of Nebraska above our hydroelectric based power purchases there. These purchases are necessary because large portions of our Members' loads in Nebraska are located east of the east/west electrical grid separation and are generally isolated from our facilities that are located west of the separation. These long-term purchase commitments represent a majority of our electric power purchases. 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 when we have excess power available above our firm commitments to both Members and non-members. We also use spot market purchases during periods of generation outages at our facilities.

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 power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use our power generating equipment for a stated period of time. The lease revenues from these arrangements are included in other operating revenue on our consolidated statements of operations. We are the lessee under power purchase arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to us the right to use power generating equipment for a stated period of time. These are 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 including 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. 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 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 $313 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. Rates for electric power sales to our Members consist of two billing components: an energy rate and a demand rate. Over the past five years, the average Member cents/ kWh sales, which is our total Member electric sales revenue divided by the kWhs sold has increased at an average of 2.2 percent per year. Member rates for energy and demand are set by our Board of Directors, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through our transmission system to our Members. In 2012, our rate schedule (A-36 rate) had an energy rate billed based upon a price per kWh of energy delivered and a demand rate based upon our Member’s highest thirty-minute integrated total demand measured using actual metered kilowatt usage in each monthly billing period during our summer peak period or the winter peak period. Beginning January 1, 2013, we implemented a rate design (A-37 rate) 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-37 rate design also had an energy rate that incorporates an on-peak and off-peak period. We developed demand response and energy shaping products to compliment the A-37 rate schedule. The participating Member’s monthly statements were adjusted using the demand response and energy shaping product incentives for Members utilizing those products. Beginning January 1, 2014, the A-38 rate design went into effect. The only change from the A-37 rate design was to implement a slight increase in the seasonal average demand rates. 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 a price per kWh of energy delivered and a demand rate based upon our Member’s highest thirty-minute integrated total demand measured using the Member’s coincident peak during our peak period in each monthly billing period during our summer peak period or the winter peak period. Three Members elected this TR-1 optional rate. Approved by our Board of Directors in September 2015 and effective January 1, 2016, we implemented a new rate design (A-39 rate) in which demand is 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 Friday, with the exception of six holidays. Energy is billed based upon a price per kWh of energy.

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 wholesale rates payable by our 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. In November 2012, three of our Members located in New Mexico filed protests with the NMPRC of the new A-37 wholesale rate that we filed with the NMPRC on October 19, 2012 and which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from our 44 Members by approximately 4.9 percent and from our 12 New Mexico Members by approximately 6.7 percent. 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. In June 2013, we attempted to withdraw the A-37 wholesale rate notice in New Mexico because our development and implementation of a new A-38 rate would likely be complete prior to NMPRC action on the suspended A-37 rate. 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 new 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 (unless terminated earlier as provided in the preliminary mediation agreement) 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 the 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 2014 and 2015, the overall impact of the New Mexico Members paying a lower rate was approximately $16.4 million and $10.7 million, respectively. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 wholesale rate, or the A-39 rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate became effective on January 1, 2016 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 7, 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC.

Master Indenture

As of December 31, 2015, 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 DSR for the twelve months ended December 31, 2015 was 1.23. 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 14 percent through 2015, and 18 percent thereafter. 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. As of December 31, 2015, our ECR was 25.1 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 cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. Accordingly, 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.

Results of Operations

General

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and a demand rate. 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. Spot 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, 2015 compared to year ended December 31, 2014

Operating Revenues

Member electric sales increased 354,067 MWhs, or 2.3 percent, to 15,780,670 MWhs in 2015 compared to 15,426,603 MWhs in 2014. Member electric sales revenue increased $25.0 million, or 2.2 percent, to $1.126 billion in 2015 compared to $1.101 billion in 2014. The increase in revenue was primarily due to an increase in oil and gas loads and higher seasonal irrigation loads.

Non-member electric sales decreased 1,245,615 MWhs, or 38.1 percent, to 2,026,525 MWhs in 2015 compared to 3,272,140 MWhs in 2014. Non-member electric sales revenue decreased $77.3 million, or 39.1 percent to $120.2 million in 2015 compared to $197.5 million in 2014. The decrease in non-member electric sales revenue was primarily due to a decrease in long-term firm energy sales to non-members of 812,880 MWhs with revenue of $41.0 million and a decrease in spot market sales of 292,768 MWhs with revenues of $12.9 million. The decrease in long-term firm energy sales to non-members was primarily due to the expiration of power sales arrangements on February 1, 2015 and September 30, 2014 that were not renewed resulting in a decrease in non-member electric sales revenue of $37.8 million in 2015 compared to 2014. When a power generating station is initially placed into service, there is generally a period of time when sales from stations are not needed to serve our Members. In such cases, we may enter into contracts with non-members, which provide revenue to us during such periods and reduce the Member revenue requirements. We generally try to time the expiration of these contracts to coincide with forecasted increased Member demand, which had the effect of reducing non-member sales following such expirations. As a result, we determined not to renew the agreements upon their expiration. The decrease in spot market sales revenue was due to the 292,768 MWh decrease in MWhs sold and lower market prices in 2015 compared to 2014. Additionally, there was a $20.0 million decrease in non-member electric sales revenue due to the recognition in 2014 of $20.0 million of regulatory liabilities previously recorded for deferred non-member electric sales revenue and there being no such recognition in 2015. The recognition in 2014 resulted in reduced Member requirements (lower Member rates) as was required in 2014 by our Board in accordance with its budgetary and rate-setting authority.

Operating Expenses

Purchased power decreased 225,317 MWhs, or 3.1 percent, to 6,931,211 MWhs in 2015 compared to 7,156,528 MWhs in 2014. Purchased power expense decreased $22.4 million, or 6.8 percent, to $305.0 million in 2015 compared to $327.4 million in 2014 due to the decrease in MWhs purchased and a 4.4 percent decrease in the average cost per MWh of purchased power due to lower market prices for power.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense decreased $61.5 million, or 21.0 percent, to $231.5 million in 2015 compared to $293.0 million in 2014. The decrease in expense was primarily due to lower coal expense resulting from the one-time $24.4 million reduction in fuel expense related to the BNSF rate transportation settlement and reduced coal consumption due to a decrease in generation of 456,404 MWhs, or 3.8 percent in 2015 compared to 2014. The largest generation decreases were Craig Station Unit 3, Escalante Station and Springerville Unit 3.

Depreciation and amortization expense increased $24.0 million, or 18.6 percent, to $152.7 million in 2015 compared to $128.7 million in 2014. The increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. Additionally, amortization expense increased $8.6 million in 2015 resulting from the amortization of transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized over the 21.4-year average life of the new debt issued and recovered from our Members in rates.

Other Income

Interest income decreased $6.7 million, or 60.4 percent, to $4.4 million in 2015 compared to $11.1 million in 2014. The decrease in interest income was primarily due to there being no investment during 2015 in the RUS cushion of credit, which earned a 5 percent return.

Year ended December 31, 2014 compared to year ended December 31, 2013

Operating Revenues

Member electric sales increased 113,116 MWhs to 15,426,603 MWhs in 2014 compared to 15,313,487 MWhs in 2013. The increase in MWhs sold in 2014 resulted in an increase of $10.4 million in Member electric sales revenue to $1.101 billion in 2014 compared to 2013.

Non-member electric sales decreased 44,347 MWhs, or 1.3 percent, to 3,272,140 MWhs in 2014 compared to 3,316,487 MWhs in 2013. Despite the decrease in MWhs sold in 2014, non-member electric sales revenue increased $25.4 million, or 14.8 percent, to $197.5 million in 2014 compared to $172.1 million in 2013. The increase in non-member electric sales revenue in 2014 was due to the recognition of $20 million of regulatory liabilities previously recorded for deferred non-member electric sales revenue. This recognition in 2014 resulted in reduced Member revenue requirements (lower Member rates) as was required in 2014 by our Board in accordance with its budgetary and rate-setting authority. The increase in non-member electric sales revenue in 2014 was also due to a 4.5 percent increase in the average price due to higher market prices, partially offset by the 1.3 percent decrease in MWhs sold for 2014.

Other operating revenue consists primarily of wheeling revenue, lease revenue, 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. 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 operating revenue increased $18.1 million, or 23.2 percent, to $96.1 million in 2014 compared to $78.0 million in 2013. The increase in other operating revenue in 2014 was primarily due to an increase of $4.8 million in lease revenues resulting from the resumption of gas tolling arrangements at the Knutson and Limon Generating Stations, higher coal sales of $10.8 million as a result of delivering more coal tons in 2014 to the other joint owners in the Yampa Project and a $1.0 million transmission surcharge related to the Nucla-Sunshine 115kv transmission project.

Operating Expenses

Purchased power increased 325,287 MWhs, or 4.8 percent, to 7,156,528 MWhs in 2014 compared to 6,831,241 MWhs in 2013. Purchased power expense increased $5.3 million, or 1.6 percent, to $327.4 million in 2014 compared to $322.1 million in 2013. The increase in expense in 2014 was due to the increase in MWhs purchased, partially offset by lower market prices for electricity.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense increased $5.4 million, or 1.9 percent, to $293.0 million in 2014 compared to $287.6 million in 2013. The increase in expense for 2014 was primarily due to higher natural gas expense resulting from an increase in generation at our natural gas-fired generating stations.

Production expense includes the operation costs for the generating stations and generation maintenance expenses for maintaining the generating facilities, such as costs of scheduled maintenance outages. Production expense increased $20.1 million, or 9.6 percent, to $229.9 million in 2014 compared to $209.8 million in 2013. The increase in expense for 2014 was primarily due to higher maintenance expenses at the Escalante and J.M. Shafer Generating Stations for turbine overhaul projects and Laramie River Generating Station Unit 2 for boiler repairs and a turbine overhaul.

Transmission expense includes the operation and maintenance costs of our transmission system and wheeling expense (amounts paid for the transmission of our electricity over transmission facilities owned by other energy companies). Transmission expense increased $6.7 million, or 4.8 percent, to $145.4 million in 2014 compared to $138.7 million in 2013. The increase was primarily due to higher maintenance expense resulting from the growth in the transmission system and increased wheeling expense.

Coal mining expense includes the Colowyo Mine operating expenses related to the portion of the coal sold from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project. Coal mining expense increased $10.9 million, or 36.5 percent, to $40.8 million in 2014 compared to $29.9 million in 2013. The increase in expense for 2014 was due to higher coal mine operating expenses related to delivering more coal to the other joint owners in the Yampa Project.

Other Income

Interest income decreased $6.2 million, or 35.9 percent, to $11.1 million in 2014 compared to $17.3 million in 2013. The decrease in interest income was due to the declining investment in the RUS cushion of credit. The investment in the RUS cushion of credit was eliminated by the 2014 debt refinancing when our RUS debt and FFB debt was entirely paid off.

Interest Expense

Interest expense, net of amounts capitalized, includes the amount of interest on outstanding long-term debt less the interest charged during construction. Interest expense decreased $7.1 million, or 4.8 percent, to $142.4 million in 2014 compared to $149.5 million in 2013. The decrease in interest expense was primarily due to lower average interest rates on principal balances.

Financial Condition

Assets

Electric plant in service increased $294 million, or 5.6 percent, to $5.487 billion as of December 31, 2015 compared to $5.193 billion as of December 31, 2014. The increase was due primarily to the completion of capital improvements and system upgrades to serve the growing needs of our Members. Additionally, land and land rights increased due to the acquisition of water rights for J.M. Shafer Generating Station and renewal of right of way easements.

Other plant consists of non-utility property and the mine assets at Colowyo Mine and New Horizon Mine. Other plant increased $17.3 million, or 8.2 percent, to $228 million as of December 31, 2015 compared to $210.7 million as of December 31, 2014. The increase was primarily due to the acquisition of land and water rights in northwestern Colorado related to the Colowyo Mine and mine equipment purchases.

Cash and cash equivalents increased $52.1 million, or 56.3 percent, to $144.6 million as of December 31, 2015 compared to $92.5 million as of December 31, 2014. The increase was primarily due to $241.0 million of proceeds from issuance of debt from our Revolving Credit Agreement and an increase in cash collected from Member accounts receivable partially offset by an increase in capital expenditures and coal inventory.

Restricted cash and investments consist of (1) funds designated by our Board for specific uses, (2) funds restricted by contract or other legal reasons, and (3) investments in securities pledged as collateral in connection with the in-substance defeasance of debt assumed in the 2011 acquisition of Colowyo Coal. The noncurrent portion of restricted cash and investments decreased $38.4 million, or 97.5 percent, to $1.0 million as of December 31, 2015 compared to $39.4 million as of December 31, 2014. The decrease was primarily due to the BNSF settlement which resolved the uncertainties related to the outcome of this matter and the $29.4 million of cash related to the BNSF settlement was no longer designated as restricted. Additionally, $8.9 million of investments in securities pledged as collateral matured in 2015. The matured U.S. Treasury Notes were used for the Colowyo Bonds principal and interest due in May and November 2015.

Coal inventory increased $18.6 million, or 45.7 percent, to $59.3 million as of December 31, 2015 compared to $40.7 million as of December 31, 2014. The increase was primarily due to a $10.6 million increase at the Craig Station as part of our coal supply planning at the station. There was also a $5.2 million increase in coal inventory at our Escalante Station and a $5.0 million increase in coal inventory at our Springerville Unit 3 due to lower generation.

Other deferred charges decreased $33.7 million, or 21.6 percent, to $122.5 million as of December 31, 2015 compared to $156.2 million as of December 31, 2014. The decrease was primarily due to $28.5 million of preliminary survey charges related to the Eastern Plains Transmission Project that was capitalized in December 2015 as part of the Burlington-Wray 230kV transmission line project.

Equity and Liabilities

Patronage capital equity increased $43.4 million, or 4.8 percent, to $952.1 million as of December 31, 2015 compared to $908.7 million as of December 31, 2014. The increase was due to a margin attributable to us of $53.4 million offset by 2015 patronage capital retirements of $10.0 million.

Noncontrolling interest represents the 49 percent of equity interests in the Springerville Partnership that is not owned by us. Noncontrolling interest decreased $545,000 to $108.8 million as of December 31, 2015 compared to $109.3 million as of December 31, 2014. The decrease was due to a Springerville Partnership net loss attributable to the noncontrolling interest of $489,000 and a partnership distribution to the noncontrolling interest of $56,000.

Long-term debt increased $129.0 million, or 4.1 percent, to $3.274 billion as of December 31, 2015 compared to $3.145 billion as of December 31, 2014, and current maturities of long-term debt decreased $1.4 million to $91.4 million compared to $92.8 million as of December 31, 2014. The net increase of $127.6 million was primarily due to debt proceeds from our Revolving Credit Agreement of $241.0 million partially offset by payments of long-term debt of $113.1 million, primarily $20.0 million for our Revolving Credit Agreement, $34.8 million for the Springerville certificates, $27.1 million for our First Mortgage Obligation, Series 2009C and $8.2 million for the Colowyo Bonds.

Liquidity

We finance our operations, working capital needs and capital expenditures from operations and issuance of debt. Our liquidity as of December 31, 2015 is as follows:

	(In thousands)
Cash and Cash Equivalents	$ 144,587
Revolving Credit Agreement Availability	431,258
Total Liquid Funds Available	**$ 575,845**

The Revolving Credit Agreement has aggregate commitments of $750 million which includes a swingline sublimit of $100 million and a letter of credit sublimit of $200 million, of which $100 million of the swingline sublimit and $152 million of the letter of credit sublimit remained available as of December 31, 2015. The Revolving Credit Agreement is secured under our Master Indenture and has a term extending through July 26, 2019. As of December 31, 2015, we have advanced funds of $271 million and issued a letter of credit for the Moffat County, CO Pollution Control Bonds in the principal amount of $46.8 million plus accrued interest. 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.

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.

Between projected cash on hand and the Revolving Credit Agreement, we believe we have sufficient liquidity to fund operations and capital financing needs.

Cash Flow

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

December 31, 2015 compared to December 31, 2014

Operating activities. Net cash provided by operating activities was $212.1 million in 2015 compared to $186.9 million in 2014, an increase of $25.2 million. Operating activities in 2015 were impacted by favorable net margins and a $10.9 million decrease in accounts receivable. Operating activities were also impacted by an $18.6 million increase in coal inventory, a $12.2 million decrease in accounts payable and accrued expenses resulting from the timing of the payment of trade payables and a $5.4 million increase in materials and supplies due to the timing of various generation projects.

Investing activities. Net cash used in investing activities was $281.1 million in 2015 compared to $214.6 million in 2014, an increase of $66.5 million. The increase was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements.

Financing activities. Net cash provided by financing activities was $121.1 million in 2015 compared to net cash used in financing activities of $72.8 million in 2014, an increase of $193.9 million. The increase in financing activities was primarily due to proceeds from issuance of debt of $241.0 million from the Revolving Credit Agreement and proceeds of $8.9 million were realized during 2015 on our investments in securities pledged as collateral related to the Colowyo Bond defeasance. The maturity of these U.S. Treasury Notes were used for the May and November 2015 Colowyo Bonds principal and interest payments.

December 31, 2014 compared to December 31, 2013

Operating activities. Net cash provided by operating activities was $186.9 million in 2014 compared to $151.7 million in 2013, an increase of $35.2 million. The increase in operating cash was primarily due to higher Member and non-member electric sales revenue, partially offset by an increase in accounts receivable, due to higher Member electric sales in 2014 compared to 2013, and a decrease in accounts payable and accrued expenses resulting from the timing of the payment of trade payables and accrued expenses.

Investing activities. Net cash used in investing activities was $214.6 million in 2014 compared to $213.0 million in 2013, an increase of $1.6 million. The increase was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements. The increase in cash used for capital expenditures was offset by an increase in proceeds from other investments related to the retirement of CFC capital term certificates.

Financing activities. Financing cash flow activity decreased $245.7 million in 2014 compared to 2013. The decrease was primarily due to higher total debt payments in 2014 of $1.740 billion, primarily $180 million for the Revolving Credit Agreement, $48.0 million for the Platte County Pollution Control Revenue Bonds, $27.1 million for our First Mortgage Obligations, Series 2009C, $32.8 million for the Springerville certificates and $1.334 billion related to the 2014 debt refinancing, partially offset by total debt proceeds of $1.690 billion, primarily $100 million from the Revolving Credit Agreement and $1.590 billion related to the 2014 debt refinancing. Additionally, patronage capital retirements increased $9.9 million in 2014 compared to 2013.

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. Without taking into account the Clean Power Plan, in the years 2016 through 2020, we forecast that we may invest approximately $1.4 billion in new facilities and upgrades to our existing facilities.

Our actual capital expenditures for existing and new generating and existing and new transmission facilities going forward depend on a variety of factors, including Member load growth, availability of necessary permits, regulatory changes, environmental requirements, current construction costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

The majority of our capital expenditures consist of additions to electric plant and equipment. Other capital projects include several transmission projects, such as expansion in the Interstate 25 corridor north of Denver, construction of the Southwest Colorado Transmission Reliability Project, and additional projects to improve reliability and load-serving capability throughout our service area. As of December 31, 2015, we have incurred capital expenditures of approximately $86.7 million, excluding land and water purchases, in connection with the expansion project of an existing coal-fired generating station called Holcomb Generating Station, which we refer to as Holcomb. Additional capital expenditures for Holcomb are not included in our current capital expenditure projections.

Outstanding Obligations

As of December 31, 2015, we had $3.4 billion in outstanding obligations, including $2.8 billion secured on a parity basis by our Master Indenture, two unsecured loan agreements totaling $56 million, the Springerville certificates totaling $495 million (which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease) and the Colowyo Bonds totaling $8 million (which are secured by funds irrevocably deposited with the trustee as part of our in-substance defeasance of such bonds and an unconditional guarantee by us).

On October 30, 2014, we issued the First Mortgage Bonds, Series 2014E-1 and E-2 in an aggregate amount of $500 million. In connection with the bonds, we entered into a registration rights agreement. On July 30, 2015, we commenced an offer to exchange the $500 million aggregate principal amount of the bonds. The exchange offer satisfied our obligations under the 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 in September 2015.

We have the Revolving Credit Agreement in the amount of $750 million. We had outstanding borrowings of $271 million and $50 million at December 31, 2015 and December 31, 2014, respectively. There is a 364-day, direct pay letter of credit issued under the Revolving Credit Agreement and provided by Bank of America for the $46.8 million Moffat County, CO, Variable Rate Demand Pollution Control Revenue Refunding Bonds, Series 2009. In November 2015, the letter of credit from Bank of America was extended for an additional 364 days to mature in January 2017. As of December 31, 2015, the availability under the Revolving Credit Agreement was $431 million.

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, 2015:

	Payments Due by Period				
Obligations	**Total**	**Less Than 1 Year**	**1 - 3 Years**	**4 - 5 Years**	**More Than 5 Years**
			(In thousands)		
Long-term Indebtedness					
Principal (1)	$ 3,364,957	$ 91,419	$ 186,359	$ 453,610	$ 2,633,569
Interest (2)	2,580,611	155,131	296,545	268,000	1,860,935
Operating Lease Obligations	23,083	5,519	17,564	—	—
Construction Obligations	82,814	63,640	19,174	—	—
Coal Purchase Obligations	562,075	102,535	313,532	146,008	—
Total	$ 6,613,540	$ 418,244	$ 833,174	$ 867,618	$ 4,494,504

(1) Principal amount in 4-5 years includes $271 million of outstanding borrowings as of December 31, 2015 under the Revolving Credit Agreement.
(2) Includes interest expense related to approximately $523 million of variable rate debt. Future variable rates are based on the LIBOR swap rate curve and the Municipal Market Advisors curve as of December 31, 2015.

We expect to fund these obligations with cash flows from operations, borrowings under the Revolving Credit Agreement and the issuance of additional long-term indebtedness.

Indebtedness. As of December 31, 2015, 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, 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, pollution control revenue bonds, and amounts outstanding under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under our Master Indenture. We have two unsecured notes totaling $56 million, the Springerville certificates totaling $495 million which are secured only by a mortgage and lien on Springerville Unit 3 and the Springerville lease, and the Colowyo Bonds totaling $8 million which are secured by funds irrevocably deposited with the trustee as part of our in-substance defeasance of such bonds and an unconditional guarantee by us.

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 began on October 1, 2009. 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.

Coal Purchase Obligations. We have commitments to purchase coal for our generating stations under long-term contracts that expire between 2017 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.

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

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s, “A (negative outlook)” by S&P, and “A (negative outlook)” 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 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 being maintained at “BBB−” or better from S&P or “Baa3” from Moody’s. We expect to enter into additional natural gas supply contracts and/or risk management contracts which will 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 began on October 1, 2009. 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, 2015 and 2014 are as follows:

	2015		2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 3,371,679	$ 3,616,946	$ 3,242,470	$ 3,716,513

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 our gas and electric sales and purchase risk and its 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 own approximately 100 MWs of oil-only turbine capacity, 357 MWs of 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 2015, these resources represented approximately only 3.2 percent of the energy we supplied to our firm load obligations.

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, an external independent assessment of our risk management programs is performed periodically per Board policy.

Interest Rate Risk

As of December 31, 2015, we were exposed to the risk of changes in interest rates related to our $522.9 million of variable rate debt, including $271.0 million outstanding under the Revolving Credit Agreement, $46.8 million of pollution control bonds and $102.9 million of variable rate CFC notes and $102.2 million of variable rate CoBank notes. As of December 31, 2015, the weighted average interest rate on this variable rate debt was 1.35 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, 2015, we had 15.5 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 $5.2 million.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

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Report of Independent Registered Public Accounting Firm

The Board of Directors of Tri-State Generation and Transmission Association, Inc.

We have audited the accompanying consolidated statements of financial position of Tri-State Generation and Transmission Association, Inc. (the Association) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Association's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tri-State Generation and Transmission Association, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Denver, Colorado
March 14, 2016

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

As of December 31,	2015	2014
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,486,518	$ 5,193,236
Construction work in progress	216,279	206,097
Total electric plant	5,702,797	5,399,333
Less allowances for depreciation and amortization	(2,240,732)	(2,129,173)
Net electric plant	3,462,065	3,270,160
Other plant	227,957	210,694
Less allowances for depreciation, amortization and depletion	(73,471)	(58,117)
Net other plant	154,486	152,577
Total property, plant and equipment	3,616,551	3,422,737
Other assets and investments		
Investments in other associations	123,686	117,976
Investments in and advances to coal mines	16,221	15,016
Restricted cash and investments	1,000	39,376
Intangible assets	25,634	32,958
Other noncurrent assets	12,139	12,531
Total other assets and investments	178,680	217,857
Current assets		
Cash and cash equivalents	144,587	92,468
Restricted cash and investments	9,530	9,784
Deposits and advances	21,673	22,224
Accounts receivable—Members	106,216	105,723
Other accounts receivable	14,270	25,693
Coal inventory	59,277	40,673
Materials and supplies	85,501	80,069
Total current assets	441,054	376,634
Deferred charges		
Regulatory assets	415,081	426,043
Prepayment—NRECA Retirement Security Plan	49,146	54,665
Other	122,535	156,200
Total deferred charges	586,762	636,908
Total assets	**$ 4,823,047**	**$ 4,654,136**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 952,082	$ 908,669
Accumulated other comprehensive income (loss)	589	(828)
Noncontrolling interest	108,757	109,302
Total equity	1,061,428	1,017,143
Long-term debt	3,273,538	3,145,246
Total capitalization	4,334,966	4,162,389
Current liabilities		
Member advances	9,403	14,576
Accounts payable	96,098	103,177
Accrued expenses	30,045	30,005
Accrued interest	34,332	32,517
Accrued property taxes	27,395	26,010
Current maturities of long-term debt	91,419	92,802
Total current liabilities	288,692	299,087
Deferred credits and other liabilities		
Regulatory liabilities	45,000	45,000
Deferred income tax liability	28,629	17,230
Intangible liabilities	6,221	9,424
Asset retirement obligations	55,215	53,754
Other	57,423	59,121
Total deferred credits and other liabilities	192,488	184,529
Accumulated postretirement benefit and postemployment obligations	6,901	8,131
Total equity and liabilities	**$ 4,823,047**	**$ 4,654,136**

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,	2015	2014	2013
Operating revenues			
Member electric sales	$ 1,125,699	$ 1,101,471	$ 1,091,103
Non-member electric sales	120,234	197,497	172,102
Other	89,515	96,123	77,958
	1,335,448	1,395,091	1,341,163
Operating expenses			
Purchased power	305,045	327,445	322,059
Fuel	231,537	293,033	287,647
Production	235,398	229,933	209,816
Transmission	153,443	145,396	138,684
General and administrative	24,708	28,591	24,325
Depreciation, amortization and depletion	152,718	128,712	121,818
Coal mining	36,130	40,849	29,889
Other	18,500	19,255	18,337
	1,157,479	1,213,214	1,152,575
Operating margins	**177,969**	**181,877**	**188,588**
Other income			
Interest income	4,355	11,076	17,288
Capital credits from cooperatives	9,189	8,684	10,922
Other income	3,981	3,573	3,344
	17,525	23,333	31,554
Interest expense, net of amounts capitalized	142,570	142,357	149,463
Income taxes	—	—	—
Net margins including noncontrolling interest	52,924	62,853	70,679
Net loss attributable to noncontrolling interest	489	1,383	2,233
Net margins attributable to the Association	**$ 53,413**	**$ 64,236**	**$ 72,912**

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,	2015	2014	2013
Net margins including noncontrolling interest	$ 52,924	$ 62,853	$ 70,679
Other comprehensive income (loss):			
Unrealized gain (loss) on securities available for sale	(125)	—	278
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,528	(4,194)	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	14	31	(358)
Income tax expense related to components of other comprehensive income (loss)	—	—	—
Other comprehensive income (loss)	1,417	(4,163)	(80)
Comprehensive income including noncontrolling interest	54,341	58,690	70,599
Net comprehensive loss attributable to noncontrolling interest	489	1,383	2,233
Comprehensive income attributable to the Association	**$ 54,830**	**$ 60,073**	**$ 72,832**

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,	2015	2014	2013
Patronage capital equity at beginning of year	$ 908,669	$ 865,379	$ 802,467
Net margins attributable to the Association	53,413	64,236	72,912
Retirement of patronage capital	(10,000)	(20,946)	(10,000)
Patronage capital equity at end of year	**952,082**	**908,669**	**865,379**
Accumulated other comprehensive income (loss) at beginning of year	(828)	3,335	3,415
Unrealized gain (loss) on securities available for sale	(125)	—	278
Unrecognized actuarial gain (loss) on postretirement benefit obligation	1,528	(4,194)	—
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	14	31	(358)
Accumulated other comprehensive income (loss) at end of year	**589**	**(828)**	**3,335**
Noncontrolling interest at beginning of year	109,302	110,740	113,027
Net loss attributable to noncontrolling interest	(489)	(1,383)	(2,233)
Equity distribution to noncontrolling interest	(56)	(55)	(54)
Noncontrolling interest at end of year	**108,757**	**109,302**	**110,740**
Total equity at end of year	**$ 1,061,428**	**$ 1,017,143**	**$ 979,454**

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,	2015	2014	2013
Operating activities			
Net margins including noncontrolling interest	$ 52,924	$ 62,853	$ 70,679
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation, amortization and depletion	152,718	126,693	118,776
Amortization of intangible asset	7,324	7,324	7,324
Amortization of NRECA Retirement Security Plan prepayment	5,520	5,519	5,457
Amortization of debt issuance costs	1,870	1,356	897
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(7,179)	(6,465)	(7,053)
Prepayment—NRECA Retirement Security Plan	—	—	(71,160)
Recognition of deferred revenue	—	(20,000)	—
Change in restricted cash and investments	29,113	—	(390)
Changes in operating assets and liabilities:			
Accounts receivable	10,936	(6,460)	7,000
Coal inventory	(18,604)	3,057	17,524
Materials and supplies	(5,432)	(4,593)	(4,119)
Accounts payable and accrued expenses	(12,188)	(5,923)	13,090
Accrued interest	1,814	7,909	(1,061)
Accrued property taxes	1,385	2,507	(189)
Other deferred credits - BNSF settlement	(29,381)	—	—
Other	21,324	13,076	(5,089)
Net cash provided by operating activities	**212,144**	**186,853**	**151,686**
Investing activities			
Purchases of plant	(290,428)	(221,613)	(212,703)
Changes in deferred charges	9,031	(8,263)	(1,849)
Proceeds from other investments	321	15,270	1,578
Net cash used in investing activities	**(281,076)**	**(214,606)**	**(212,974)**
Financing activities			
Member advances	(7,041)	2,227	(2,129)
Payments of long-term debt	(113,063)	(1,739,835)	(196,490)
Proceeds from issuance of debt	240,183	1,674,977	258,873
Debt refinancing transaction costs	—	(184,073)	—
Decrease in advance payments to RUS	—	137,727	130,257
Retirement of patronage capital	(8,286)	(20,582)	(10,711)
Proceeds from investment in securities pledged as collateral	8,931	8,723	8,410
Change in restricted cash and investments	327	48,000	(15,357)
Net cash provided by (used in) financing activities	**121,051**	**(72,836)**	**172,853**
Net increase (decrease) in cash and cash equivalents	**52,119**	**(100,589)**	**111,565**
Cash and cash equivalents – beginning	**92,468**	**193,057**	**81,492**
Cash and cash equivalents – ending	**$ 144,587**	**$ 92,468**	**$ 193,057**
Supplemental cash flow information:			
Cash paid for interest	$ 154,657	$ 152,344	$ 166,828
Supplemental disclosure of noncash investing and financing activities:			
Change in plant expenditures included in accounts payable	$ 2,173	$ (4,691)	$ 5,276
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. ("the Association") is a taxable wholesale electric power generation and transmission cooperative organized for the purpose of providing electricity to our 44 member distribution systems ("Members"), that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our electric power to other utilities in the region pursuant to long-term contracts and spot sale arrangements. In 2015, 2014 and 2013, total megawatt-hours sold were 17.8, 18.7 and 18.6 million, respectively, of which 89, 85 and 86 percent, respectively, were sold to Members. Total revenue from electric sales was $1.2, $1.3, and $1.3 billion for 2015, 2014 and 2013 of which 90, 85 and 86 percent, respectively, was from Member sales. Energy resources were provided by generation and purchased power, of which 63, 63 and 64 percent were from generation for 2015, 2014 and 2013, respectively.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members and extending through 2040 for the remaining two Members, and subject to automatic extension thereafter until either party provides at least a two year 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 it requires for the operation of its system. 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, 2015, 16 Members have made such an election.

Revenue from one Member, United Power, Inc., was $147.1 million, or 13.1 percent of our Member revenue, and 11 percent of our overall revenue, in 2015. No other Member exceeded 10 percent of our Member revenue or our overall revenue in 2015.

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 long-term debt 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 facilities, long-term purchase contracts and forward, short-term and spot market 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 1,561 people, of which 361 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 11—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 generation facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Craig Station Units 1 and 2 (operated by us ("Yampa Project")), 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). 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.

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 any of 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 11—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 and liabilities as expenses or as a reduction in expenses concurrent with their recovery in rates.

Regulatory assets and liabilities are as follows (thousands):

	2015	2014
Regulatory assets		
Deferred income tax expense (1)	$ 28,629	$ 17,230
Deferred prepaid lease expense- Craig 3 Lease (2)	16,183	22,656
Deferred prepaid lease expense- Springerville 3 Lease (3)	92,878	95,168
Goodwill – J.M. Shafer (4)	60,541	63,390
Goodwill – Colowyo Coal (5)	41,327	43,526
Deferred debt prepayment transaction costs (6)	175,444	184,073
Other	79	—
	415,081	426,043
Regulatory liabilities		
Deferred revenues (7)	45,000	45,000
Net regulatory asset	$ 370,081	$ 381,043

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.
(2) Deferral of 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 and amortization expense in the amount of $6.5 million annually through the remaining original life of the lease ending in 2018 and recovered from our Members in rates.
(3) Deferral of 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 and amortization 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 and amortization 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 and amortization expense 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 and amortization 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 recognition of $10 million of non-member electric sales revenue received in 2008 and $35 million of non-member electric sales revenue in 2011. These deferred non-member electric sales revenues will be refunded to Members through reduced rates when recognized in non-member electric sales revenue in future periods.

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 facilities, long-term purchase contracts and forward, short-term and spot market 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.

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.

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 4.4, 4.7 and 4.8 percent were used for 2015, 2014 and 2013, respectively. The amount of interest capitalized during construction was $13.5, $15.0 and $13.0 million during 2015, 2014 and 2013, 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.

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 power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use our power generating equipment for a stated period of time. The lease revenues from these arrangements are included in other operating revenue on the consolidated statements of operations. We are the lessee under power purchase arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to us the right to use power generating equipment for a stated period of time. These are included in other operating expenses on the consolidated statements of operations. See Note 8—Leases.

INVESTMENTS IN OTHER ASSOCIATIONS: Investments in other associations includes 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 (thousands):

	2015	2014
Basin Electric Power Cooperative	$ 84,875	$ 80,250
National Rural Utilities Cooperative Finance Corporation	26,808	26,695
CoBank, ACB	6,212	5,518
Western Fuels Association, Inc.	2,275	2,338
Other	3,516	3,175
Investments in other associations	$ 123,686	$ 117,976

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 the owner of Western Fuels-Wyoming, Inc. ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. We, through our ownership in WFA, advance funds to the Dry Fork Mine.

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

	2015	2014
Investment in Trapper Mine	$ 14,072	$ 13,650
Advances to Dry Fork Mine	2,149	1,366
Investments in and advances to coal mines	$ 16,221	$ 15,016

CASH AND CASH EQUIVALENTS: We consider highly liquid investments with an original maturity of three months or less to be cash equivalents.

RESTRICTED CASH AND INVESTMENTS: 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 is for the payment of debt within one year and funds restricted by contract that are expected to be settled within one year. These funds are therefore classified as current on the statements of financial position. The other funds are for the payment of debt beyond one year and 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 the statements of financial position.

We have investments in U.S. Treasury Notes pledged as collateral in connection with the in-substance defeasance for the principal outstanding and future interest payments on the Coal Contract Receivable Collateralized Bonds ("Colowyo Bonds"). The balances in these investments are described as investments in securities pledged as collateral in the table below. As of December 31, 2015, the entire $8.7 million balance of the defeasance investment is for Colowyo Bond debt payments due within one year and is, therefore, a current asset on the consolidated statements of financial position. The Colowyo Bonds mature in November 2016.

We received $29.4 million in 2009 from BNSF Railway Company ("BNSF") as a reduction of prior coal delivery shipping charges as the result of the decision of the Surface Transportation Board ("STB"). However, BNSF appealed the decision and the funds were subject to refund in the event BNSF was ultimately successful in its appeal. These funds were designated by our Board to be held as restricted cash. In May 2015, BNSF, WFA and Basin filed a joint petition at the STB informing the STB that the parties had entered into a rail transportation agreement settling all matters at issue. In June 2015, the STB granted the joint petition, which resolved the uncertainties related to the outcome of this matter and the $29.4 million of cash related to the BNSF settlement was no longer designated as restricted.

Restricted cash and investments are as follows (thousands):

	2015	2014
Investments in securities pledged as collateral	$ 8,671	$ 9,192
Funds restricted by contract	859	592
Restricted cash and investments - current	9,530	9,784
BNSF settlement	—	29,381
Funds restricted by contract	1,000	1,000
Investments in securities pledged as collateral	—	8,995
Restricted cash and investments - noncurrent	1,000	39,376
Total restricted cash and investments	$ 10,530	$ 49,160

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, 2015, 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 $129,000. At December 31, 2014, the cost and estimated fair value of the investments were $1.1 and $1.4 million, respectively, with a net unrealized gain balance of $254,000. The estimated fair value of the investments is included in other noncurrent assets on the consolidated statements of financial position. The unrealized gains at December 31, 2015 and 2014 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.

We hold U.S. Treasury Notes to maturity in connection with the December 2011 defeasance of the Colowyo Bonds and these are included in restricted cash and investments on the statements of financial position. Since they will be held to maturity, the notes are carried at amortized cost. As of December 31, 2015, the defeasance investment of $8.7 million consisted of a principal amount of $7.4 million, an unamortized premium of $113,000 and cash of $1.1 million. As of December 31, 2014, the defeasance investment of $18.2 million consisted of a principal amount of $16.4 million, an unamortized premium of $371,000 and cash of $1.4 million.

INVENTORIES: Coal inventories at our owned generating stations are stated at LIFO (last-in, first-out) cost and were $42.2 and $22.2 million at December 31, 2015 and 2014, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. In 2014, we realized lower coal fuel expense of $596,000 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. As of December 31, 2015, preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Station Project of $86.7 million (see Note 12—Commitments and Contingencies—Legal). In December 2015, $28.5 million of preliminary survey charges related to the Eastern Plains Transmission Project was capitalized as part of the Burlington-Wray 230kV transmission line project and is included in electric plant-construction work in progress on the consolidated statements of financial position.

We make advance payments to the operating agents of jointly owned facilities. See Note 3—Property, Plant and Equipment—Jointly Owned Facilities.

Other deferred charges are as follows (thousands):

	2015	2014
Preliminary surveys and investigations	$107,146	$131,693
Advances to operating agents of jointly owned facilities	11,537	20,567
Other	3,852	3,940
Total other deferred charges	$122,535	$156,200

DEBT ISSUANCE COSTS: We adopted Accounting Standards Update ("ASU") 2015-03, *Interest — Imputation of Interest (Subtopic 835-30)* and ASU 2015-15, *Interest – Imputation of Interest (Subtopic 835-30) Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* Accordingly, we accounted 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. The adoption of these amendments resulted in $21.2 million and $22.3 million of debt issuance costs being presented as a direct deduction from long-term debt as of December 31, 2015 and 2014. The $22.3 million of debt issuance costs as of December 31, 2014 were retrospectively adjusted as a change in accounting principle and were previously reported in other deferred charges.

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 including 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.

Fossil steam 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 fossil steam generating stations.

Transmission: We have an asset retirement obligation to remove a certain transmission line and related substation assets resulting from an agreement to relocate the line.

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

	2015	2014
Asset retirement obligation at beginning of year	$ 53,754	$ 52,585
Liabilities incurred	1,802	1,366
Liabilities settled	(3,028)	(5,729)
Accretion expense	3,324	2,250
Change in cash flow estimate	(637)	3,282
Asset retirement obligation at end of year	$ 55,215	$ 53,754

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 far value.

MEMBERSHIPS: There are 44 $5 memberships outstanding at December 31, 2015 and 2014.

PATRONAGE CAPITAL: Our net margins are treated as advances of capital by 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 revenue, lease revenue, 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. 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 (the "Yampa Participants"). The associated Colowyo Mine expenses are included in coal mining, depreciation and amortization and interest expense on the consolidated statements of operations.

INCOME TAXES: We are a non-exempt cooperative subject to federal and state taxation and, as a cooperative, are allowed a tax exclusion for margins allocated as patronage capital. The liability method of accounting for income taxes is utilized, whereby 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.

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 $1.6 and $1.5 million at December 31, 2015 and 2014, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was $108,630, $(452,500) and $2.6 million in 2015, 2014 and 2013, respectively.

EVALUATION OF SUBSEQUENT EVENTS: We evaluated subsequent events through March 14, 2016, which is the date when the financial statements were issued.

NEW ACCOUNTING PRONOUNCEMENTS: In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. In July 2015, FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU 2014-09 replaces current revenue guidance, which was based on a risks and rewards model, with a transfer of control model. The core principle under the new transfer of control model states 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, this amendment requires the following steps: (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 amendment also requires additional quantitative and qualitative disclosures sufficient enough to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, this amendment 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 with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes footnote disclosures). Reporting entities have the option to adopt the standard as early as the original January 1, 2017 effective date of this amendment. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In August 2014, the FASB issued ASU 2014-15, *Presentation of Financial Statements Going Concern (Subtopic 205-40); Disclosures of Uncertainties about an Entity's Ability to Continue as a Going Concern.* The amendment in this ASU requires management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern, which is currently performed by the external auditors. Management will be required to perform this assessment for both interim and annual reporting periods and must make certain disclosures if it concludes that substantial doubt exists. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meets its obligations as they become due within one year after the date that that the financial statements are issued (or within one year after the date that the financial statements are available to be issued when applicable). The amendment is effective for annual periods, and interim periods within those annual periods, beginning on or after December 15, 2016. We are currently evaluating the impact of this amendment on our financial position and results of operations. The adoption of this update is not expected to have a material impact on the financial position or results of operations.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810), Amendments to the Consolidation Analysis*. The amendments in this ASU affect reporting entities that are required to evaluate whether they should consolidate certain legal entities. All legal entities are subject to reevaluation under the revised consolidation model. Specifically, ASU 2015-02: (1) modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (2) eliminates the presumption that a general partner should consolidate a limited partnership, and (3) affects the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships. The amendment is effective for the fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted, including adoption in an interim period. A reporting entity may apply the amendments in this ASU using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption. A reporting entity also may apply the amendments retrospectively. We adopted this update in 2015 and it did not have a material impact on our financial position or results of operations.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740); Balance Sheet Classification of Deferred Taxes.* The amendments in this ASU simplify the presentation of deferred income taxes. Deferred tax assets and liabilities must all be classified as noncurrent. This amendment is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. We adopted this update in 2015 and it did not have a material impact on our financial position or results 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*. The amendments in this ASU require that equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) be measured at fair value, with subsequent changes in fair value recognized in net income. An entity may choose to measure equity investments that do not have readily determinable fair value at cost minus impairment. The pronouncement impacts financial liabilities under 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 financial position and results of operations.

In February 2016, the FASB issued ASU No. 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. Short-term leases of 12 months or less are excluded from this amendment. 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The guidance is to be applied using a modified retrospective transition method with the option to elect a package of practical expedients. We are currently evaluating the impact of this amendment on our financial position and results of operations.

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 the 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 (thousands):

	Annual Depreciation Rate			2015	2014
Generation plant	0.44 %	to	3.16 %	$ 3,498,248	$ 3,379,305
Transmission plant	2.00 %	to	2.88 %	1,294,151	1,161,462
General plant	3.00 %	to	33.33 %	430,842	392,963
Other	2.80 %	to	5.60 %	263,277	259,506
Electric plant in service (at cost)				5,486,518	5,193,236
Construction work in progress				216,279	206,097
Less allowances for depreciation and amortization				(2,240,732)	(2,129,173)
Electric plant				$ 3,462,065	$ 3,270,160

At December 31, 2015, we had $82.8 million of commitments to complete construction projects, of which approximately $63.6, $14.3 and $4.9 million are expected to be incurred in 2016, 2017 and 2018, respectively.

JOINTLY OWNED FACILITIES: Our share in each jointly owned facility is as follows as of December 31, 2015 (these electric plant in service, accumulated depreciation and construction work in progress amounts are included in the electric plant table above) (thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Station Units 1 and 2	24.00 %	$ 345,937	$ 229,464	$ 23,518
MBPP - Laramie River Station	24.13 %	389,283	288,386	13,791
San Juan Project – San Juan Unit 3	8.20 %	82,754	61,369	562
Total		$ 817,974	$ 579,219	$ 37,871

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 Western Fuels-Colorado ("WFC"), a limited liability company 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. WFC also owns Colowyo Coal, which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. We also own a 50 percent undivided ownership in the land and the rights to mine the property known as Fort Union Mine. Our share of the coal provided from these mines is primarily used by us for generation at our generating facilities. The expenses related to this coal used by us are included in fuel expense on the consolidated statements of operations.

Other plant assets are as follows (thousands):

	2015	2014
Colowyo Mine assets	$ 166,157	$ 152,549
New Horizon Mine assets	48,373	44,812
Fort Union Mine assets	1,158	2,007
Accumulated depreciation and depletion	(67,601)	(52,580)
Net mine assets	148,087	146,788
Non-utility assets	12,269	11,326
Accumulated depreciation	(5,870)	(5,537)
Net non-utility assets	6,399	5,789
Net other plant	$ 154,486	$ 152,577

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 "PPA"). The $55.5 million intangible asset represents the amount that the PPA 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 PPA through June 30, 2019. The straight-line method is consistent with the terms of the PPA 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 PPA intangible asset is accounted for as a reduction of the revenue generated by the PPA and is included in other operating revenue. The amortization was $7.3 million in each of the years 2015, 2014 and 2013 and will be recognized over each of the next four years as follows (thousands):

2016	$ 7,324
2017	7,324
2018	7,324
2019	3,662
	$ 25,634

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 has to sell coal to the Yampa Participants through 2017. The $18.0 million intangible liability represents the amount that the coal sale contract terms were below market at the acquisition date and is being amortized based upon the contracted tonnage with the Yampa Participants over the remaining life of the coal contract ending December 31, 2017. The intangible liability balance of $6.2 and $9.4 million as of December 31, 2015 and 2014, respectively, is included in intangible liabilities. The amortization of the Colowyo Coal intangible liability is accounted for as an increase in other operating revenue. An amortization benefit of $3.2, $3.2 and $2.5 million was recognized in 2015, 2014 and 2013, respectively, and the recognition of the benefit over the next two years is estimated to be as follows (thousands):

2016	$ 3,125
2017	3,096
	$ 6,221

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 except for two unsecured notes in the aggregate amount of $55.9 million as of December 31, 2015. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance and an unconditional guarantee by us. All long-term debt contains certain restrictive financial covenants, including a DSR requirement and ECR requirement.

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

	2015	2014
Mortgage notes payable		
3.66% to 8.08% CFC, 5.96% average for 2015, due through 2028	$ 86,979	$ 92,977
2.63% to 6.17% CoBank, ACB, 4.35% average for 2015, due through 2042	278,086	287,798
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 Obligation, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	180,000
First Mortgage Obligation Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	20,000
First Mortgage Obligation Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	550,000
First Mortgage Obligation, Series 2009C, Tranche 1, 6.00%, due through 2019	108,571	135,714
First Mortgage Obligation, Series 2009C, Tranche 2, 6.31%, due through 2021	110,000	110,000
Variable rate CFC, as determined by CFC, 2.90% average for 2015, due through 2026	644	687
Variable rate CFC, LIBOR-based term loan, 1.48% average for 2015, due through 2049	102,220	102,220
Variable rate CoBank, ACB, LIBOR-based term loan, 1.74% average for 2015, due through 2044	102,220	102,220
Variable rate, Revolving Credit Agreement, LIBOR-based revolving credit, 1.25% average for 2015, due through 2019	271,000	50,000
Pollution control revenue bonds		
City of Gallup, NM, 5.00%, Series 2005, due through 2017	10,815	15,840
Moffat County, CO Variable Rate Demand Series 2009, 0.06% average for 2015, due 2036	46,800	46,800
Springerville certificates		
Series A, 6.04%, due through 2018	89,968	124,779
Series B, 7.14%, due through 2033	405,000	405,000
Colowyo Coal		
Colowyo Bonds, 10.19%, due through 2016	7,693	15,899
Other	1,683	2,536
Total debt	$ 3,371,679	$ 3,242,470
Less debt issuance costs	(21,201)	(22,254)
Less debt discounts	(8,739)	(8,894)
Plus debt premiums	23,218	26,726
Total debt adjusted for discounts, premiums and debt issuance costs	$ 3,364,957	$ 3,238,048
Less current maturities	(91,419)	(92,802)
Long-term debt	$ 3,273,538	$ 3,145,246

On October 30, 2014, we issued the First Mortgage Bonds, Series 2014 E-1 and E-2 (“Series 2014 Bonds”) in an aggregate amount of $500 million. In connection with the Series 2014 Bonds, we entered into a registration rights agreement. On July 30, 2015, we commenced an offer to exchange the $500 million aggregate principal amount of the Series 2014 Bonds. The exchange offer satisfied our obligations under the 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 in September 2015.

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”). We had outstanding borrowings of $271 million and $50 million at December 31, 2015 and December 31, 2014, respectively. There is a 364-day, direct pay letter of credit issued under the Revolving Credit Agreement and provided by Bank of America, N.A. for the $46.8 million Moffat County, CO, Variable Rate Demand Pollution Control Revenue Refunding Bonds, Series 2009. In November 2015, the letter of credit from Bank of America was extended for an additional 364 days to mature in January 2017. As of December 31, 2015, the availability under the Revolving Credit Agreement was $431 million.

Annual maturities of total debt adjusted for debt issuance costs, discounts and premiums at December 31, 2015 are as follows (thousands):

2016	$ 91,419
2017	108,037
2018	78,322
2019 (1)	368,776
2020	84,834
Thereafter	2,633,569
	$ 3,364,957

(1) Annual maturities in 2019 include $271 million of outstanding borrowings under the Revolving Credit Agreement.

NOTE 6—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 utilize observable market data in active markets for identical assets or liabilities.

Level 2 inputs consist of observable market data, other than that included in Level 1, that is either directly or indirectly observable.

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 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. Changes in the net unrealized gains or losses are reported as a component of comprehensive income. The carrying amounts and fair values of our marketable securities are as follows (thousands):

	As of December 31, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Marketable securities	$ 1,022	$ 1,151	$ 1,095	$ 1,349

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 at December 31, 2015 and December 31, 2014 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.

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 carrying amounts and fair values of our debt are as follows (thousands):

	2015		2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 3,371,679	$ 3,616,946	$ 3,242,470	$ 3,716,513

NOTE 7 – INCOME TAXES

We had no income tax expense or benefit in 2015, 2014 and 2013.

The liability method of accounting for income taxes is utilized, whereby 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 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 (thousands):

	2015	2014
Deferred tax assets		
Safe harbor lease receivables	$ 35,945	$ 38,218
Net operating loss carryforwards	152,936	131,935
Alternative minimum tax credit carryforwards	3,834	3,834
Deferred revenues	16,933	16,933
Colowyo Coal- coal contract intangible liability	2,341	3,547
Other	35,332	46,856
	247,321	241,323
Deferred tax liabilities		
Basis differences- property, plant and equipment	160,494	152,497
Capital credits from other associations	38,663	36,790
Deferred debt prepayment transaction costs	66,020	69,266
Other	10,773	—
	275,950	258,553
Net deferred tax liability	$ (28,629)	$ (17,230)

The $11.4 million increase in the net deferred tax liability from $17.2 million at December 31, 2014 to $28.6 million at December 31, 2015 is not recognized as a tax expense in 2015 due to our regulatory accounting treatment of deferred taxes. Instead, the tax expense is deferred and reflected as an increase 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 $28.6 million and $17.2 million at December 31, 2015 and 2014, respectively.

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

	2015	2014	2013
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	(0.58)	1.40	(6.74)
Postretirement medical actuarial gains and losses	(1.09)	2.44	0.18
Various book tax differences	2.84	4.52	8.93
Regulatory treatment of deferred taxes	(1.17)	(8.36)	(2.37)
Effective tax rate	0.00 %	0.00 %	0.00 %

We had a taxable loss of $54.0 million for 2015. At December 31, 2015, we have a federal net operating loss carryforward of $406.4 million which, if not utilized, will expire between 2030 and 2035. The future reversal of existing temporary differences will more-likely-than-not enable the realization of the net operating loss carryforward. We have $3.8 million of alternative minimum tax credit carryforwards at December 31, 2015 to offset future regular taxes payable and the credit carryforwards 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 2012 forward. We do not have any liabilities recorded for uncertain tax positions.

NOTE 8—LEASES

LESSOR—GAS TOLLING ARRANGEMENTS: We are the lessor under certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use power generating equipment for a stated period of time. These arrangements include sales contracts to a third party out of our J.M. Shafer, Knutson and Limon Generating Stations. Under the first of these contracts, the third party directs the use of 122 megawatts of the 272 -megawatt net 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. Under the other contracts, the third party directs the use of both of the two Knutson Generating Station units and one of the two Limon Generating Station units over the terms of the contracts under tolling arrangements whereby the third party provides its own natural gas for generation of electricity. The Limon contract was suspended for a four -year period beginning May 2009 through April 2013 and the Knutson contract was suspended for a three -year period beginning May 2010 through April 2013 to allow us to utilize the output of the turbines. Both turbine contracts resumed with the third party under the original tolling arrangements on May 1, 2013 and are in effect through April 30, 2016. We also had a similar tolling arrangement with a third party through September 30, 2014 involving one of the four 40 -megawatt units at our Pyramid Generating Station. The revenues from these operating leases of $30.1, $30.6 and $25.8 million for 2015, 2014 and 2013, respectively, are accounted for as lease revenue and are reflected in other operating revenue on the consolidated statements of operations. The generating units used in these gas tolling arrangements have a total cost and accumulated depreciation of $223 and $106 million, respectively, as of December 31, 2015, and of $232 and $108 million, respectively, as of December 31, 2014.

The minimum future lease revenues under these gas tolling arrangements at December 31, 2015 are as follows (thousands):

2016	$ 18,745
2017	11,734
2018	11,734
2019	5,867
	$ 48,080

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 2015, 2014 and 2013 is included in other operating expenses on the consolidated statements of operations. Our operating lease commitments for this gas tolling arrangement at December 31, 2015 are as follows (thousands):

2016	$ 5,519
2017	5,678
2018	5,855
2019	6,031
	$ 23,083

NOTE 9—RELATED PARTIES

TRAPPER MINING, INC.: We, and certain participants in the Yampa Project, own Trapper Mining. Organized as a cooperative, Trapper Mining supplied 26, 35 and 24 percent of the coal for the Yampa Project in 2015, 2014 and 2013, respectively. Our 26.57 percent share of coal purchases from Trapper Mining was $17.7, $30.6 and $16.9 million in 2015, 2014 and 2013, respectively. Our membership interest in Trapper Mining of $14.1 and $13.7 million at December 31, 2015 and 2014, respectively, is included in investments in and advances to coal mines on the consolidated statements of financial position. Our share of Trapper Mining capital credit allocations of $531,000 for

2015, and $532,000 in each of the years 2014 and 2013 is included in capital credits from cooperatives on the consolidated statements of operations.

NOTE 10—EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of our 1,561 employees participate in the National Rural Electric Cooperative Association Retirement Security Plan ("RS Plan") except for the 216 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 2015, 2014 and 2013 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 $22.9, $21.5 and $92.6 million in 2015, 2014 and 2013, respectively. Contributions in 2013 were significantly higher than those in 2015 and 2014 due to our election to exercise the prepayment option offered to participating employers in 2013.

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 361 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, 2015, and over 80 percent funded at January 1, 2014, 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 361 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the 216 employees of Colowyo Coal, we contribute 1 percent of an employee's eligible earnings. 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 $3.0, $2.9 and $3.0 million in 2015, 2014 and 2013, respectively.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: We sponsor three medical plans for all non-bargaining unit employees. 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, 2015, 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 plans were amended as of December 31, 2015. The plan amendment eliminated coverage for all members after the age of 65. This did not impact the valuation as post-65 retiree contributions were sufficient to cover expected claim costs for that group, so there was no implicit subsidy to value. The postretirement medical benefit plan was amended to include three different plan options for members prior to the age of 65. This reduced the liability by approximately 11.5 percent and is reflected as a prior service cost in the amount of ($896,214) as of December 31, 2015.

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 the consolidated statements of financial position as follows (thousands):

	2015	2014
Postretirement medical benefit obligation at beginning of year	$ 7,713	$ 2,957
Service cost	593	582
Interest cost	270	256
Plan amendments - prior service cost	(896)	—
Benefit payments (net of contributions by participants)	(325)	(276)
Actuarial (gain) loss	(632)	4,194
Postretirement medical benefit obligation at end of year	$ 6,723	$ 7,713
Postemployment medical benefit obligation at end of year	178	418
Total postretirement and postemployment medical obligations at end of year	$ 6,901	$ 8,131

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 the 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 (thousands):

	2015	2014
Actuarial gain included in accumulated other comprehensive income at beginning of year	$ (1,082)	$ 3,081
Reclassification adjustment included in income	14	31
Plan amendments - prior service cost	896	—
Actuarial gain (loss) per actuarial study	632	(4,194)
Actuarial gain (loss) included in accumulated other comprehensive income at end of year	$ 460	$ (1,082)

The assumptions used in the 2015 actuarial study performed for our postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.90 %
Initial health care cost trend (2015)	8.00 %
Ultimate health care cost trend	4.50 %
Year that the rate reached the ultimate health care cost trend rate	2025
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	12.09

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 (thousands):

	1% Increase	1% Decrease
Accumulated postretirement medical benefit obligation	$ 709	$ (620)
Net periodic postretirement medical benefit expense	$ 131	$ (109)

The following are the expected future benefits to be paid related to the postretirement medical benefit obligation (thousands):

2016	$ 362
2017	433
2018	473
2019	535
2020	561
2021 and thereafter	2,600
	$ 4,964

NOTE 11 – 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") of the Springerville Unit 3. We, as general partner, 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 \$853.3 and \$874.4 million at December 31, 2015 and 2014, respectively, the long-term debt of \$511.0 and \$548.1 million at December 31, 2015 and 2014, respectively, accrued interest associated with the long-term debt of \$14.3 million and \$15.2 million at December 31, 2015 and 2014, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of \$108.8 and \$109.3 million at December 31, 2015 and 2014, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of \$21.0 million for 2015 and 2014. Our consolidated statements of operations also include interest expense of \$32.3 million, \$34.1 million and \$35.9 million for 2015, 2014, and 2013. The net losses attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership are 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 and spot coal for the Springerville Unit 3 in Arizona. 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 isn't 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. There is shared power with a related party (Basin), which results in power and the ability to receive benefits from the significant activities of WFA. Due to Basin's participating interest of 42.27 percent interest in MBPP and ownership of the Dry Fork Station, Basin is the party most closely associated to 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 for both December 31, 2015 and 2014, respectively, and is included in investments in other associations.

Western Fuels – Wyoming: WFW, the owner and operator of the Dry Fork Mine in Gillette, WY, 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 isn't 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 isn't 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 $14.1 million at December 31, 2015 and $13.7 million at December 31, 2014.

NOTE 12—COMMITMENTS AND CONTINGENCIES

SALES: We have delivery obligations under resource-contingent power sales contracts with Public Service Company of Colorado totaling 125 megawatts in the summer season and 175 megawatts in the winter season. These contracts expire in 2016 and 2017. We also have a resource-contingent firm power sales contract of 100 megawatts to Salt River Project Agricultural Improvement and Power District through August 31, 2036.

COAL PURCHASE REQUIREMENTS: We are committed to purchase coal for our generating plants under long-term contracts that expire between 2017 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, 2015, the annual minimum coal purchases under these contracts are as follows (thousands):

2016	$ 102,535
2017	105,457
2018	103,389
2019	104,686
2020	82,612
Thereafter	63,396
	$ 562,075

ELECTRIC POWER PURCHASE AGREEMENTS: Our principal long-term electric power purchase contracts are with Western Area Power Administration ("WAPA") and Basin. WAPA, one of four power marketing administrations of the U.S. Department of Energy, markets and supplies cost-based hydroelectric power and related services primarily to cooperatives and municipal electric systems located in 15 states in the central and western United States. WAPA markets and transmits the power to us under 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 (terminate September 30, 2024). We have entered into a new contract with WAPA relating to the Loveland Area Project which commences upon termination of the above referenced contract terminating September 30, 2024, and will run through September 2054.

Our purchases of hydroelectric-based electric power from WAPA are made at cost-based rates under long-standing federal law under which WAPA sells power to cooperatives and municipal electric systems and certain other preference customers. We utilize a portion of our electric purchases from Basin to supply power to our Nebraska members, which are primarily located east of the electrical grid separation and are generally isolated from our generating facilities that are located west of the separation. We have a contract with Basin for a term ending December 31, 2050, to supply the electrical requirements of its Nebraska members in excess of power supplied by WAPA. We also purchase 225 MWs from Basin for use west of the electrical separation under a contract for a term ending December 31, 2050.

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

	2015	2014	2013
WAPA	$ 89,986	$ 91,639	$ 91,038
Basin	127,500	132,649	136,223

ENVIRONMENTAL: Our electric generation facilities are subject to various operating permits and must operate within guidelines imposed by numerous environmental regulations. We believe these facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL: On October 19, 2012, we gave notice, as required by New Mexico law, to the New Mexico Public Regulation Commission ("NMPRC") of our new A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from all 44 of our Members by approximately 4.9 percent, with revenues from our 12 New Mexico Members increasing by approximately 6.7 percent. 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 June 25, 2013, we filed to withdraw the 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 new A-38 wholesale rate which was scheduled to become effective on January 1, 2014. 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 (unless terminated earlier as provided in the preliminary mediation agreement) 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 the 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 2015 and 2014, the overall revenue impact of the New Mexico Members paying a lower rate was approximately $10.7 million and $16.4 million, respectively. On October 9, 2015, we gave notice, as required by New Mexico law, to the NMPRC of our 2016 wholesale rate, or the A-39 rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate became effective on January 1, 2016 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 7, 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.

On March 4, 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the Colorado Public Utilities Commission ("COPUC") alleging that our A-37 rate design was unjust and unreasonable. On April 4, 2013, we filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over our wholesale rates. The COPUC assigned the matter to an Administrative Law Judge ("ALJ"). The ALJ bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board, and secondly to hear the facts in the case depending on jurisdiction. The ALJ conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the ALJ's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the ALJ's decision and remanded the case to the ALJ to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The ALJ entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate. On December 28, 2015, we and the three Colorado Members filed a joint motion with the COPUC to withdraw the complaint and dismiss the proceeding. On January 19, 2016, the ALJ granted our joint motion to withdraw the complaint, dismiss the proceeding with prejudice and close the proceeding. The ALJ's order has become effective by operation of law.

The Purchase Option and Development Agreement was executed on July 26, 2007 between us and Sunflower Electric Power Corporation ("Sunflower") and other Sunflower parties. The agreement calls for us to make option payments totaling $55 million to Sunflower and/or the other Sunflower parties in exchange for the development rights to develop a new coal-fired generating unit or units at Sunflower's existing single-unit Holcomb Station in western Kansas. Upon execution, $25 million was paid. In 2008, $5 million was paid and the remainder will be paid on the purchase date. The purchase date will be designated by us, Sunflower and the other parties to the Purchase Option and Development Agreement after we exercise our option to acquire the development rights. The purchase date cannot currently be estimated due to legal uncertainties surrounding the status of the necessary air permits. The original air permit application was denied by the Kansas Department of Health and Environment ("KDHE") in October 2007 and we and Sunflower appealed the denial to the Kansas courts. Subsequent to the denial of the air permit, Sunflower entered into an agreement with the governor of Kansas that could result in the KDHE issuing a permit for one new coal-fired generating unit at Holcomb Station of 895 megawatts. As a result of the agreement, Sunflower and we withdrew the appeal of the denial of the original air permit application. The KDHE issued the new permit on December 16, 2010. The Sierra Club filed an appeal of the new permit with the Kansas Court of Appeals on January 14, 2011 and the case was immediately transferred to the Kansas Supreme Court. The Kansas Supreme Court remanded the permit to the KDHE to consider a limited issue. The KDHE issued an addendum to the permit on May 30, 2014. The Sierra Club filed an appeal with the Kansas Court of Appeals on June 27, 2014. On November 3, 2014, the Kansas Supreme Court granted a pending motion to transfer the case from the Court of Appeals and KDHE subsequently filed the record on appeal. The Kansas Supreme Court heard oral argument on the appeal on January 28, 2016. Excluding the cost of land and water rights, the cost of developing the units incurred by us as of December 31, 2015 is $86.7 million, which is included in other deferred charges on the consolidated statements of financial position. We are unable to project the ultimate outcome of this matter or when the air permit application process may conclude.

In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five days in northern New Mexico, primarily on national forest service land in the Santa Fe National Forest. Six plaintiff groups, comprised 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 the 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. 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 are also jointly liable for any negligence by JMEC under joint venture and alter ego theories. On June 16, 2014, we filed multiple motions for summary judgment including for plaintiffs' claims related to nuisance, trespass, negligence per se, independent duty, joint venture and alter ego. On December 29, 2014, we received a demand letter from the U.S. Department of Justice for costs incurred as a result of the fire, also alleging the joint venture theory. JMEC has settled with 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. Settlement demands were received from plaintiffs Jemez Pueblo and Pueblo de Cochiti claiming damages in the amount of approximately $34.4 million and $23.9 million, respectively, focusing mainly on damages arising from flooding subsequent to the fire. On March 9, 2015, the district court granted our motions for summary judgment related to nuisance, trespass, negligence per se, and alter ego, but denied our motions related to independent duty and joint venture. On March 17, 2015, we filed an application for interlocutory appeal with the New Mexico Court of Appeals related to the district court's denial of our motions for summary judgment for plaintiffs' claims related to independent duty and joint venture. The New Mexico Court of Appeals denied our application for interlocutory appeal on May 27, 2015. A jury trial commenced on September 28,

2015. 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. On November 11, 2015, we filed a request with the district court to certify for interlocutory appeal certain issues regarding our duty under a negligence claim, which was denied by the district court in January 2016. Three or four separate trials will occur in the second half of 2016 and first quarter of 2017 to determine the amount of damages. We maintain $100 million in liability insurance coverage for this matter. Although we cannot predict the outcome of these matters 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.

In May 2013, near the Village of Pecos, New Mexico, a wildfire known as the Tres Lagunas Fire was ignited and subsequently destroyed timber on thousands of acres and burned for approximately three weeks. On March 25, 2014, a lawsuit was filed by David Old d/b/a Old Wood, The Viveash Ranch, and River Bend Ranch, LLC, against our Member, Mora-San Miguel Electric Cooperative, Inc. ("MSMEC"), in the First Judicial District Court for the County of Santa Fe, New Mexico. In the complaint, plaintiffs allege that the Tres Lagunas Fire resulted from wind blowing a portion of a dead standing tree into an electric distribution power line owned and operated by MSMEC. On November 6, 2015, plaintiffs filed a motion to amend their complaint and include the addition of us as a defendant. The district court approved the motion to amend on November 20, 2015 and plaintiffs' first amended complaint was filed. Plaintiffs assert claims of negligence, violations of New Mexico's Unfair Practices Act ("NMUPA"), and strict liability. On December 21, 2015, we filed a motion to dismiss the NMUPA and strict liability claims and, additionally, filed our answer and 12-person jury demand. In 2014, we renewed our coverage and now maintain $200 million in liability insurance coverage for this matter. Although we cannot predict the outcome of this matter at this point in time, we do not expect it to have a material adverse effect on our financial condition or our future results of operations or cash flows.

NOTE 13—QUARTERLY FINANCIAL DATA (UNAUDITED)

Unaudited operating results by quarter for 2015 and 2014 are presented below. In the opinion of management, all adjustments (consisting of normal recurring accruals) necessary for the fair statement of the results of operations for such periods have been included:

Statement of Operations Data (thousands):	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
2015					
Operating revenues	$ 328,391	$ 305,913	$ 388,102	$ 313,042	$ 1,335,448
Operating margins	49,384	38,550	81,412	8,623	177,969
Net margins attributable to the Association	20,126	6,284	48,302	(21,299)	53,413
2014					
Operating revenues	$ 349,198	$ 327,288	$ 396,479	$ 322,126	$ 1,395,091
Operating margins	53,652	34,098	69,603	24,524	181,877
Net margins attributable to the Association	24,511	3,373	40,451	(4,099)	64,236

Our business is influenced by seasonal weather conditions, changes in rates and other factors. In the fourth quarter of 2015, net margins were negative primarily due to increased depreciation and amortization expense resulting from renewed right-of-way easements, and the completion of capital projects and putting them into service. Fuel expense increased due to increased generation and increased coal costs due to higher per ton mine production costs. Net margins in the fourth quarter of 2014 were lower primarily due to decreased non-member electric sales and increased production expense resulting from scheduled maintenance outages at our coal-fired generating stations.

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 our disclosure controls and procedures are effective.

This annual report does not include a report on management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by the SEC for newly public companies.

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 44 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. The members of our Board and their ages as of March 1, 2016 are as follows:

NAME	AGE	MEMBER-REPRESENTATIVE
Rick Gordon—Chairman and President	62	Mountain View Electric Association, Inc.
Tony Casados—Vice Chairman	70	Northern Rio Arriba Electric Association, Inc.
Leo Brekel—Secretary	64	Highline Electric Association
Stuart Morgan—Treasurer	69	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	64	High Plains Power, Inc.
Julie Kilty—Assistant Secretary	57	Wyrulec Company
Joseph Herrera—Executive Committee	41	Socorro Electric Cooperative, Inc.
William Mollenkopf—Executive Committee	66	Empire Electric Association, Inc.
Joseph Wheeling—Executive Committee	53	La Plata Electric Association, Inc.
Robert Bledsoe	66	K.C. Electric Association, Inc.
Jerry Burnett	69	High West Energy, Inc.
Richard Clifton	74	Carbon Power & Light, Inc.
Arthur W. Connell	62	Central New Mexico Electric Cooperative, Inc.
Lucas Cordova Jr.	50	Jemez Mountains Electric Cooperative, Inc.
John Finnerty	76	Wheatland Rural Electric Association, Inc.
Gary Fuchser	61	Northwest Rural Public Power District
John Gavan	59	Delta Montrose Electric Association
Jack Hammond	81	Niobrara Electric Association, Inc.
Ronald Hilkey	76	White River Electric Association, Inc.
Ralph Hilyard	77	Roosevelt Public Power District
Donald Kaufman	77	Sangre de Cristo Electric Association, Inc.
Donald Keairns	56	San Isabel Electric Association, Inc.
Hal Keeler	87	Columbus Electric Cooperative, Inc.
Thaine Michie	75	Poudre Valley Rural Electric Association, Inc.
Virginia Mondragon	50	Mora-San Miguel Electric Cooperative, Inc.
Christopher Morgan	47	Gunnison County Electric Association, Inc.
Richard Newman	65	United Power, Inc.
Stanley Propp	69	Chimney Rock Public Power District
Timothy Rabon	55	Otero County Electric Cooperative, Inc.
Gary Rinker	64	Southwestern Electric Cooperative, Inc.
Arthur Rodarte	67	Kit Carson Electric Cooperative, Inc.
Claudio Romero	69	Continental Divide Electric Cooperative, Inc.
Donald Russell	68	Big Horn Electric Company
Brian Schlagel	66	Morgan County Rural Electric Association
Donald Schutz	69	Springer Electric Cooperative, Inc.
Jack Sibold	70	San Miguel Power Association, Inc.
Charles J. Soehner	71	Y-W Electric Association, Inc.
Darryl Sullivan	65	Sierra Electric Cooperative, Inc.
Jerry Thompson	53	Garland Light & Power Company
Carl Trick II	68	Mountain Parks Electric, Inc.
Douglas Shawn Turner	54	The Midwest Electric Cooperative Corporation
Scott Wolfe	52	San Luis Valley Rural Electric Cooperative, Inc.
William Wright	75	Southeast Colorado Power Association
Phillip Zochol	40	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 WFC, WFA, and Trapper Mining. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Limon and Calhan, Colorado.

Tony Casados has served on our Board since July 2000 and is Vice Chairman of the Board. He is a member of the Executive Committee and the Engineering and Operations Committee. Mr. Casados serves as President of Northern Rio Arriba Electric Cooperative, Inc. He is a self-employed rancher and co-owner and operator of Casados Ranch Partnership. Mr. Casados also serves as a director of WFA.

Leo Brekel has served on our Board since March 2003 and is Secretary 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 and Midwest Electric Consumers Association.

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 Engineering and Operations 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.

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

Joseph Herrera has served on our Board since January 2014. He is a member of the Executive Committee and External Affairs-Member Relations Committee. Mr. Herrera is the General Manager for Socorro Electric Cooperative, Inc.

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.

Joseph Wheeling has served on our Board since May 2010. He is a member of the Executive Committee and Finance and Audit Committee. Mr. Wheeling serves as a director of La Plata Electric Association, Inc. He is a partner of both James Ranch Beef and The Gardens @ James Ranch. He is also a partner of Germann Wheeling Cattle Company. Mr. Wheeling is Chairman of the board of directors of FastTrack Communications. He is also a director on the board of directors of MacElvain Energy Inc. and an advisor for Serious Texas BBQ.

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, Inc. 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 and serves as a Commissioner of the Colorado State Land Board.

Jerry Burnett has served on our Board since November 2013. He is a member of the Engineering and Operations Committee. Mr. Burnett serves as Treasurer 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 Secretary/Treasurer on the board of directors of Wyoming Rural Electric Association.

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

Lucas Cordova Jr. has served on our Board since August 2013. He is a member of the External Affairs-Member Relations Committee. Mr. Cordova serves as a director of Jemez Mountains Electric Cooperative, Inc. He is also the owner of Aspen Tree and Crane Service.

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 a director of Wheatland Rural Electric Association, Inc. He is also a rancher in Wheatland, Wyoming. Mr. Finnerty also serves as a director of WFC.

Gary Fuchser has served on our Board since August 2013. He is a member of the External Affairs-Member Relations 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.

John Gavan has served on our Board since June 2015. He is a member of the External Affairs-Member Relations Committee. Mr. Gavan serves as a director of Delta-Montrose Electric Association. He also serves as a director of Solar Energy International and is the technology manager for the Delta County Library District.

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 retired.

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.

Donald Keairns has served on our Board since April 2012. He is a member of 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.

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 farm owner-operator and has also been a bank board member for 1st New Mexico Bank for 20 years. He also serves as a director of WFA.

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 WFC.

Virginia Mondragon has served on our Board since June 2014. She is a member of the External Affairs-Member Relations Committee. Ms. Mondragon serves as a director of Mora-San Miguel Electric Cooperative, Inc. and is employed by Mora Valley Community Health Services Inc.

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 External Affairs-Member Relations Committee. He serves as a director of Gunnison County Electric Association, Inc. and is self-employed. Mr. Morgan is also a director of the Office of Resource Efficiency and Rural Transportation Authority. He is a council person for the town of Mt. Crested Butte 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 CEO of Thoro Products Company, Inc., a past Building Manager for Bluhill Park Partners, and a partner in the Gilpin Aerial Tram Enterprise. In 1999, Mr. Newman was convicted for feloniously storing hazardous waste (2 drums of degreasing solvent) in violation of Colorado law and sentenced to four years in the custody of the Colorado Department of Corrections. The violation stemmed from Mr. Newman's activities as a supervisor and as president of Thoro Products Company, Inc., a 113 year-old Colorado cleaning products manufacturer, which was also convicted in Colorado proceedings related to the same storage of hazardous waste. On June 19, 2006, the Supreme Court of Colorado declined to hear Mr. Newman's final appeal of his sentence.

Stanley Propp has served on our Board since April 2015. He is also 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.

Timothy Rabon has served on our Board since April 2014. He is a member of the Engineering and Operations Committee. Mr. Rabon serves as a director 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 Mesa Verde Materials, which is a mining and aggregate production and trucking operation. He is also owner of MV2, which is a land holding and construction and demolition landfill operation.

Gary Rinker has served on our Board since June 2007. He is a member of the Finance and Audit Committee. Mr. Rinker is the General Manager of Southwestern Electric Cooperative, Inc.

Arthur Rodarte has served on our Board since July 2008. He is a member of the Finance and Audit Committee. Mr. Rodarte serves as a trustee of Kit Carson Electric Cooperative, Inc. He is part owner of Oliver's Inc., which is a general store.

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.

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 the owner of Schlagel Farms. He is also a crop adjuster for Rural Community Insurance Services.

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 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 WFC.

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 director 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.

Jerry Thompson has served on our Board since June 2007. He is a member of the Finance and Audit Committee. Mr. Thompson serves as President of Garland Light & Power Company. He is the President and employee of Waterwork Irrigation, 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 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 S. Turner has served on our Board since April 2015. He is a member of the External Affairs-Member Relations Committee. Mr. Turner serves as Vice 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. Mr. Turner also serves as President of the Perkins County School Board.

Scott Wolfe has served on our Board since June 2008. He is a member of the Engineering and Operations Committee. Mr. Wolfe serves as President of San Luis Valley Rural Electric Cooperative, Inc. He has been a farmer and owner of Lobo Farm LLC.

William Wright has served on our Board since April 1994. 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 External Affairs-Member Relations 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 either 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, 2016:

NAME	AGE	POSITION
Micheal McInnes	63	Chief Executive Officer
Joel Bladow	57	Senior Vice President, Transmission
Patrick L. Bridges	57	Senior Vice President/Chief Financial Officer
Ellen Connor	58	Senior Vice President, Organizational Services/Chief Technology Officer
Jennifer Goss	46	Senior Vice President, Member Relations
Barry Ingold	52	Senior Vice President, Generation
Bradford Nebergall	57	Senior Vice President, Energy Management
Kenneth V. Reif	64	Senior Vice President, General Counsel
Barbara Walz	53	Senior Vice President, Policy & Compliance/Chief Compliance Officer

Micheal S. McInnes is our Chief Executive Officer and has served in that position since June 2014. Prior to that Mr. McInnes was Interim Executive Vice President and General Manager from March 2014 to June 2014 and was 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 18 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 33 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 33 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 May 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 more than 32 years of experience in the electric energy sector. He has a Master's of Science degree in applied economics from the University of Texas at Dallas, Masters of Business Administration and Bachelors of Business Administration degrees from West Texas State University, and is a Certified Public Accountant and Chartered Financial Analyst.

Ellen Connor is our Senior Vice President, Organizational Services/Chief Technology Officer and has served in that position since July 2014. Prior to that Ms. Connor 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's of Science in Business Administration and is a Certified Treasury Professional. Ms. Connor has over 33 years of experience in the electric utility industry.

Jennifer Goss is our Senior Vice President, Member Relations and has served in that position since July 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 17 years of electric utility experience.

Barry Ingold is our Senior Vice President, Generation and has served in that position since March 2014. Prior to that Mr. Ingold was Senior Manager, Production Assets and has served in numerous engineering and management roles since joining Tri-State in 2004. In addition to his 17 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 holds 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 July 2008. Mr. Nebergall previously served as Senior Manager, Energy Markets. 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, National Association). Mr. Nebergall has a Master's of Business Administration degree from the University of Houston and a Bachelor's of Science degree in finance from Iowa State University. Mr. Nebergall has 29 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 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's of Arts degree from California Polytechnic State University and a Jurisprudence Doctor degree from the University of Denver. He has 36 years of utility experience.

Barbara Walz is our Senior Vice President, Policy & Compliance/Chief Compliance Officer and has served in that position since February 2011. In November 2012, Mrs. Walz's title changed from Senior Vice President, External Affairs & Environment to her current title. 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 graduated from the University of North Dakota with a Bachelor's of Science degree in chemical engineering and earned a Master's Degree in environmental policy and management from the University of Denver. She has diverse experience and worked for the North Dakota Health Department, a National Trade Association in Washington D.C., and as the Director of Compliance for a worldwide environmental consulting firm. She has 29 years' experience developing and implementing corporate compliance programs.

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.tristategt.org.

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 executed retention agreements for certain executive officers as deemed appropriate, as described below.

Retirement Plans

Defined Benefit Plan. We participate in the NRECA Retirement Security 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, WFC, working at the New Horizon Mine. This plan is a qualified pension plan under IRC Section 401(a). 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 two 401(k) plans (NRECA and Fidelity Investments) to all our employees. We contribute 1 percent of employee base salary (split $^1/_2$ percent into each plan) for all non-bargaining employees. We offer one 401(k) plan (NRECA) to all employees of WFC 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 (NRECA) to certain employees of WFC 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. Under the NRECA 401(k) plan, all employees are eligible to contribute up to 100 percent of their salary on a pre-tax basis. Under the Fidelity Investments 401(k) plan, all employees are eligible to contribute up to 60 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.

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 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
Tony Casados
Leo Brekel
Stuart Morgan
Matt M. Brown
Julie Kilty
Joseph Herrera
William Mollenkopf
Joseph Wheeling

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, Tony Casados, Leo Brekel, Stuart Morgan, Matt M. Brown, Julie Kilty, Joseph Herrera, William Mollenkopf, and Joseph Wheeling 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. Casados is our Vice Chairman, Mr. Brekel is our Secretary, Mr. Morgan is our Treasurer, Mr. Brown is our Assistant Secretary and Ms. Kilty is our Assistant Secretary. All of the members of our executive committee are employees or 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 2015.

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 2015). 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 McInnes	2015	$ 680,711	$ —	$ — (2)	$ 38,577	$ 719,288
Chief Executive Officer	2014	529,528	—	— (3)	34,406	563,934
	2013	386,576	7,350	443,113	35,942	872,981
Patrick Bridges	2015	401,413	—	240,449	49,718	691,580
Senior VP/CFO	2014	381,754	—	61,660	46,424	489,838
	2013	316,064	—	150,601	47,321	513,986
Ellen Connor	2015	265,138	—	400,891	27,960	693,989
Senior VP, Organizational	2014	203,078	—	— (3)	14,195	217,273
Services/CTO	2013	179,121	—	175,731	8,649	363,501
Barbara Walz	2015	316,163	—	288,468	37,977	642,608
Senior VP, Policy	2014	269,036	—	— (3)	19,671	288,707
& Compliance/CCO	2013	259,550	—	162,609	22,103	444,262
Bradford Nebergall	2015	374,872	—	193,205	47,479	615,556
Senior VP, Energy	2014	349,758	—	60,047	44,086	453,891
Management	2013	339,562	7,350	151,115	43,548	541,575

(1) Includes 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 Retirement Security 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.
(3) Change in pension value was negative.

Retention Agreements

Tri-State has retention agreements for the following employees: 1) Senior Manager, Internal Audit, 2) Senior Vice President, Transmission, 3) Senior Vice President, Energy Management, 4) Senior Vice President, Policy & Compliance/Chief Compliance Officer, 5) Senior Vice President, Member Relations, 6) Senior Vice President, General Counsel and 7) Senior Vice President/Chief Financial Officer.

The retention agreements were made effective April 30, 2014 and end on March 31, 2016. In consideration of the above mentioned employees continuing employment during this period, the employee is eligible to receive a retention payment on April 1, 2016 in the amount agreed to in the agreement as follows:

Employee Title	Retention Payment
Senior Manager, Internal Audit	$ 31,827
Senior Vice President, Transmission	79,000
Senior Vice President, Energy Management	87,000
Senior Vice President, Policy & Compliance/CCO	66,950
Senior Vice President, Member Relations	64,375
Senior Vice President, General Counsel	79,825
Senior Vice President/Chief Financial Officer	95,000

The retention agreement is not an employment agreement and does not guarantee the employee the right to continue in the employment of Tri-State or its subsidiaries.

Defined Benefit Plan

The following table lists the estimated values under the NRECA Retirement Security Plan and the Pension Restoration Plan as of December 31, 2015. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits is limited to $260,000 effective January 1, 2015.

Name	Number of years Credited Service as of December 31, 2015	NRECA Retirement Security Plan Present Value of Accumulated Benefit as of December 31, 2015	Pension Restoration Plan Present Value of Accumulated Benefit as of December 31, 2015	Payments During 2015
Micheal McInnes	8 months (1)	$ 3,230	$ 1,535,781	$ 2,317,465 (1)
Patrick Bridges	8 years, 3 months	542,894	148,095	None
Ellen Connor	33 years, 10 months	1,516,500	—	None
Barbara Walz	17 years, 10 months	972,787	15,734	None
Bradford Nebergall	7 years, 3 months	474,907	147,029	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 Pension Restoration Plan is 32 years, 9 months.

There is a one year waiting period after commencement of employment before participants are eligible for the Retirement Security Plan. This waiting period is waived if the participant was previously eligible for the NRECA Retirement Security 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, 2015.

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. Per this policy, the directors are compensated 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 2015 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 2015. Directors are also reimbursed for expenses as described above.

Name	2015 Board Fees(1)
Robert Bledsoe	$ 29,000
Leo Brekel	39,800
Matt M. Brown	24,500
Jerry Burnett	20,500
Tony Casados	46,500
Richard Clifton	30,000
Arthur W. Connell(2)	16,500
Lucas Cordova Jr.	28,500
John Finnerty(2)	34,500
Gary Fuchser	21,500
John Gavan	9,000
Rick Gordon(4)	183,452
Ronald Hagan(3)	8,000
Jack Hammond	32,000
Ronald Hilkey	19,000
Ralph Hilyard	17,000
Donald Kaufmann	8,500
Donald Keairns	22,300
Hal Keeler	39,000
Julie Kilty	26,500
Bart Laemmel(3)	12,500
Gary Merrifield(3)	22,500
Thaine Michie(2)	27,000
William Mollenkopf	36,500
Virginia Mondragon	21,000
Christopher Morgan	16,500
Stuart Morgan	37,500
Rick Newman	22,000
William Patterson(3)	10,500
Stanley Propp	12,500
Timothy Rabon	18,000
Gary Rinker	20,500
Arthur Rodarte	21,900
Claudio Romero	20,000
Donald Russell	21,500
Brian Schlagel	25,500
Donald Schutz	7,750
Gerald Seward(3)	12,500
Jack Sibold	19,500
Charles J. Soehner(2)	52,100
Kevin Stuart(3)	17,700
Darryl Sullivan	29,000
Jerry Thompson	21,750
Carl Trick II	26,000
Douglas Shawn Turner	15,000
Joseph Wheeling	26,500
Scott Wolfe	24,000
William Wright	25,500
Phillip Zochol	13,750

(1) Various board members have deferred a total of $44,425 of the actual Board fee payments made in 2015.
(2) Includes fees received for serving as a director of our subsidiary, WFC.
(3) Individual ceased serving on the Board prior to December 31, 2015.
(4) Includes personal use of auto allowance which is grossed up to cover taxes.

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 2015.

Certain of our directors serve on the board of managers of WFC, 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 WFC for the purchase of coal for our facilities that exceeded $120,000 in 2015, which transactions were eliminated through financial consolidation. We purchased coal for the Yampa Project from Trapper Mining that exceeded $120,000 in 2015.

Other than as described above, in 2015, 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.

	2015	2014
Audit Fees(1)	$ 871,000	$ 1,351,500
Audit-Related Fees(2)	—	—
Tax Fees(3)	50,500	31,500
All Other Fees(4)	—	—
Total	$ 921,500	$ 1,383,000

(1) Audit of annual financing statements and review of 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.
(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 2015 and 2014, 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 S-4 Registration Statement, 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.)
4.2†	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.)
4.5.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.5.2*	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
4.6.1*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.6.2*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9035, in the original principal amount of $38,220,475.57
4.6.3*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9038, in the original principal amount of $943,092.72
4.6.4*	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

4.6.5* 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
4.7.1* Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.7.2* First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997
4.7.3* 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
4.7.4* Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.7.5* 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
4.8.1* Loan Agreement, dated July 21, 2013, between Tri-State and Basin Electric Power Cooperative
4.8.2* Promissory Note, dated July 21, 2013, from Tri-State to Basin Electric Power Cooperative, in the original amount of $850,000
4.9.1* Master Loan Agreement, dated June 8, 2006, between Tri-State and CoBank, ACB
4.9.2* Amendment to Master Loan Agreement, dated June 8 2006, between Tri-State and CoBank, ACB related to Loan No. ML0303T5
4.9.3* 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
4.10.1* Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.10.2* 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
4.11.1* Unsecured Term Loan Agreement, dated June 10, 2013, between Tri-State and CoBank, ACB
4.11.2* 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
4.12.1* Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.12.2* 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
4.12.3* 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
4.13.1* Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.13.2* Secured Promissory note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077
4.14.1* 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-0047-9078
4.15* Bond, dated July 1, 2005, pursuant to the Indenture of Trust, dated July 1, 2005, between City of Gallup, New Mexico and Bank of New York, in the original amount of $55,910,000, related to City of Gallup, New Mexico, Pollution Control Revenue Refunding Bonds, Series 2005A.
4.16* Bond, Dated February 1, 2009, 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 Variable Rate Demand 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

4.18.1* 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* Bond, dated December 6, 1994, from Colowyo Coal Funding Corp, pursuant to the Trust Indenture between Colowyo Coal Funding Corp and Bank of New York Mellon as successor trustee to the Chase Manhattan Bank, in the original amount of $100,000,000 due in 2016

4.20.1* Security Agreement, dated June 1, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.

4.20.2* Promissory Note, dated June 1, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc., in the original principal amount of $895,000

4.20.3* Security Agreement, dated July 7, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.

4.20.4* Promissory Note, dated July 7, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc., in the principal original amount of $1,160,712

4.20.5* Security Agreement, dated March 25, 2011, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.

4.20.6* Promissory Note, dated March 25, 2011, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc., in the original principal amount of $843,011

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

4.21.2* 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† Amended and Restated Wholesale Power Contract, dated as of January 16, 1975, between Tri-State and Basin Electric Power Cooperative, as amended by Amendment No 1, dated October 7, 1987, Amendment No. 2, dated as of December 14, 1995, Amendment No. 3, dated as of July 1, 2002, Amendment No. 4, dated as of November 24, 2004, and Amendment No. 5, dated as of December 12, 2006 (Filed as Exhibit 10.1 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.2† 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.)

10.3† Wholesale Electric Service Contract, dated November 1, 2001, between Tri-State and Delta-Montrose Electric Association, together with a schedule identifying one other substantially identical Wholesale Electric Service Contract (Filed as Exhibit 10.3 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.4† 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.)

10.5† 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.)

10.6.1† 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.)

10.6.2† 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.)

10.7† 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.)

10.8† 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.)

10.9† 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.)

10.10**† 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.)

10.11**† Retention Agreement for Joel K. Bladow, effective as of April 30, 2014, between Tri-State and Joel K. Bladow (Filed as Exhibit 10.11 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.12**† Retention Agreement for Patrick L. Bridges, effective as of April 30, 2014, between Tri-State and Patrick L. Bridges (Filed as Exhibit 10.12 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.13**† Retention Agreement for Jennifer Godin Goss, effective as of April 30, 2014, between Tri-State and Jennifer Godin Goss (Filed as Exhibit 10.13 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.14**† Retention Agreement for Bradford C. Nebergall, effective as of April 30, 2014, between Tri-State and Bradford C. Nebergall (Filed as Exhibit 10.14 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.15**† Retention Agreement for John O' Flannigan, effective as of April 30, 2014, between Tri-State and John O' Flannigan (Filed as Exhibit 10.15 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.16**† Retention Agreement for Kenneth V. Reif, effective as of April 30, 2014, between Tri-State and Kenneth V. Reif (Filed as Exhibit 10.16 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.17**† Retention Agreement for Barbara A. Walz, effective as of April 30, 2014, between Tri-State and Barbara A. Walz (Filed as Exhibit 10.17 to the Registrant's Form S-4 Registration Statement, File No. 333-203560.)

10.18**† 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.)

10.19**†	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. The Company hereby agrees to furnish a copy to the SEC upon request.

** Management contract or compensatory plan arrangement.

† Incorporated herein by reference.

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 14, 2016

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 14, 2016
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	March 14, 2016
/s/ STEVEN J. LINDBECK Steven J. Lindbeck	Senior Manager Controller (principal accounting officer)	March 14, 2016
/s/ RICK GORDON Rick Gordon	Chairman, President and Director	March 14, 2016
/s/ TONY CASADOS Tony Casados	Director	March 14, 2016
/s/ LEO BREKEL Leo Brekel	Director	March 14, 2016
/s/ STUART MORGAN Stuart Morgan	Director	March 14, 2016
/s/ MATT M. BROWN Matt M. Brown	Director	March 14, 2016
/s/ JULIE KILTY Julie Kilty	Director	March 14, 2016
/s/ JOSEPH HERRERA Joseph Herrera	Director	March 14, 2016

/s/ WILLIAM MOLLENKOPF William Mollenkopf	Director	March 14, 2016
/s/ JOSEPH WHEELING Joseph Wheeling	Director	March 14, 2016
/s/ ROBERT BLEDSOE Robert Bledsoe	Director	March 14, 2016
/s/ JERRY BURNETT Jerry Burnett	Director	March 14, 2016
/s/ RICHARD CLIFTON Richard Clifton	Director	March 14, 2016
/s/ ARTHUR W. CONNELL Arthur W. Connell	Director	March 14, 2016
/s/ LUCAS CORDOVA, JR. Lucas Cordova, Jr.	Director	March 14, 2016
/s/ JOHN FINNERTY John Finnerty	Director	March 14, 2016
/s/ GARY FUCHSER Gary Fuchser	Director	March 14, 2016
/s/ JOHN GAVAN John Gavan	Director	March 14, 2016
/s/ JACK HAMMOND Jack Hammond	Director	March 14, 2016
/s/ RONALD HILKEY Ronald Hilkey	Director	March 14, 2016
/s/ RALPH HILYARD Ralph Hilyard	Director	March 14, 2016
/s/ DONALD KAUFMAN Donald Kaufman	Director	March 14, 2016

/s/ DONALD KEAIRNS Donald Keairns	Director	March 14, 2016
/s/ HAL KEELER Hal Keeler	Director	March 14, 2016
/s/ THAINE MICHIE Thaine Michie	Director	March 14, 2016
/s/ VIRGINIA MONDRAGON Virginia Mondragon	Director	March 14, 2016
/s/ CHRISTOPHER MORGAN Christopher Morgan	Director	March 14, 2016
/s/ RICHARD NEWMAN Richard Newman	Director	March 14, 2016
/s/ STANLEY PROPP Stanley Propp	Director	March 14, 2016
/s/ TIMOTHY RABON Timothy Rabon	Director	March 14, 2016
/s/ GARY RINKER Gary Rinker	Director	March 14, 2016
/s/ ARTHUR RODARTE Arthur Rodarte	Director	March 14, 2016
/s/ CLAUDIO ROMERO Claudio Romero	Director	March 14, 2016
/s/ DONALD RUSSELL Donald Russell	Director	March 14, 2016
/s/ BRIAN SCHLAGEL Brian Schlagel	Director	March 14, 2016
/s/ DONALD SCHUTZ Donald Schutz	Director	March 14, 2016
/s/ JACK SIBOLD Jack Sibold	Director	March 14, 2016

Signature	Title	Date
Charles J. Soehner	Director	
/s/ DARRYL SULLIVAN Darryl Sullivan	Director	March 14, 2016
/s/ JERRY THOMPSON Jerry Thompson	Director	March 14, 2016
/s/ CARL TRICK II Carl Trick II	Director	March 14, 2016
/s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	March 14, 2016
/s/ SCOTT WOLFE Scott Wolfe	Director	March 14, 2016
/s/ WILLIAM WRIGHT William Wright	Director	March 14, 2016
/s/ PHILLIP ZOCHOL Phillip Zochol	Director	March 14, 2016

Appendix A

Calculation of Financial Ratios

Equity to Capitalization Ratio

Indenture ECR	**As of December 31, 2015** ($ in thousands)	
Total Debt	$	2,845,071
Total Margins & Equities		952,917
Total Capitalization	$	**3,797,988**
Indenture ECR		**25.1%**

Debt Service Ratio

	Year Ended December 31, 2015 ($ in thousands)	
Net Margins Available for Debt Service		
Net Margins	$	53,413
Interest Expense		123,007
Amortization of debt discount or premium		155
Depreciation, depletion, obsolescence, amortization of property rights, etc.		127,224
Accrued taxes on income		0
Lease Expenses		66,335
Income from funds irrevocably deposited		0
AFUDC and/or capitalized interest		0
Net Margins Available for Debt Service (NMADS)	$	370,134
Annual Debt Service Requirements		
Principal of all debt of the Company	$	49,252
Interest on all debt coming due		118,269
Amortization of Balloon Payments		51,733
Escrowed Payments with Respect to Defeased Debt		0
Lease Payments		82,125
Annual Debt Service Requirement (ADSR)	$	301,379
Debt Service Ratio		**1.23**