

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

Form S-4

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

**TRI-STATE GENERATION AND TRANSMISSION
ASSOCIATION, INC.**

(Exact name of registrant as specified in its charter)

Colorado
(State or other jurisdiction of
incorporation or organization)

4911
(Primary Standard Industrial
Classification Code Number)

84-0464189
(IRS Employer
Identification Number)

**1100 W 116th Avenue
Westminster, Colorado 80234
(303) 452-6111**

(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Kenneth V. Reif, Esq.
Senior Vice President and General Counsel
1100 W 116th Avenue
Westminster, Colorado 80234
(303) 452-6111

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copy to:

Steven Khadavi, Esq.
David P. Swanson, Esq.
Dorsey & Whitney LLP
51 West 52nd Street
New York, New York 10019
(212) 415-9200

Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after the effective date of this registration statement.

If the securities being registered on this form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box.

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

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 the 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
(Do not check if a smaller reporting company)

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issuer Tender Offer)
Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer)

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	Amount to be registered	Proposed maximum offering price per unit(1)	Proposed maximum aggregate offering price(1)	Amount of registration fee
4.25% First Mortgage Bonds, Series 2016A, due 2046	\$250,000,000	100%	\$250,000,000	\$25,175

(1) The registration fee has been calculated pursuant to Rule 457(f) under the Securities Act of 1933, as amended. The proposed maximum offering price is estimated solely for the purpose of calculating the registration fee.

The registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, or until the Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

SUBJECT TO COMPLETION, DATED JUNE 14, 2016

PROSPECTUS



TRI-STATE

Generation and Transmission
Association, Inc.

A Touchstone Energy® Cooperative



TRI STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Offer to Exchange

***\$250,000,000 aggregate principal amount of 4.25% First Mortgage Bonds,
Series 2016A, due 2046
that have been registered under the Securities Act of 1933
for any and all outstanding unregistered 4.25% First Mortgage Bonds,
Series 2016A, due 2046***

We are offering to exchange an aggregate principal amount of \$250,000,000 of registered 4.25% First Mortgage Bonds, Series 2016A, due 2046, or the new bonds, for any and all of our outstanding unregistered 4.25% First Mortgage Bonds, Series 2016A, due 2046, or the old bonds, that were issued in a private offering on May 23, 2016.

We are offering to exchange the new bonds for the old bonds to satisfy our obligations contained in the registration rights agreement that we entered into in connection with the issuance of the old bonds. We will not receive any proceeds from the exchange offer, and issuance of the new bonds will not result in any increase in our outstanding debt.

The terms of the new bonds will be identical in all material respects to the terms of the old bonds, except that the transfer restrictions, registration rights and additional interest provisions relating to the old bonds will not apply to the new bonds.

We do not intend to list the new bonds on any securities exchange or seek approval for quotation through any automated trading system.

You may withdraw your tender of old bonds at any time prior to the expiration of the exchange offer. We will exchange all of the outstanding old bonds that are validly tendered and not validly withdrawn prior to the expiration of the exchange offer for an equal principal amount of new bonds.

The exchange offer expires at 5:00 p.m., New York City time, on _____, 2016, unless extended by us.

Broker-dealers receiving new bonds in exchange for old bonds acquired for their own account through market-making or other trading activities must deliver a prospectus in any resale of the new bonds.

See “Risk Factors” beginning on page 13 for a discussion of certain risks that you should consider in connection with the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is _____, 2016

The information in this prospectus is not complete and may be changed. We may not complete the exchange offer and issue these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell nor is it soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Table of Contents

Forward-looking Statements	ii
Summary	1
Risk Factors	13
Use of Proceeds	24
Capitalization	25
Selected Consolidated Financial Data	26
Management’s Discussion and Analysis of Financial Condition and Results of Operations	29
Tri-State Generation and Transmission Association, Inc.	47
Legal Proceedings	72
Directors and Executive Officers	75
Compensation Discussion and Analysis	82
Executive Compensation	84
Security Ownership of Certain Beneficial Owners and Management	88
Related Party Transactions and Director Independence	89
The Exchange Offer	90
Description of the Bonds	100
Description of the Master Indenture	105
Material U.S. Federal Income Tax Consequences	112
Plan of Distribution	113
Legal Matters	114
Experts	114
Where You Can Find More Information	114
Appendix A—Calculation of Financial Ratios	A-1
Index to Financial Statements	F-1

This prospectus incorporates business and financial information about us that is not included in or delivered with this prospectus. Such information is available without charge to holders of our securities upon written or oral request to Tri-State Generation and Transmission Association, Inc., 1100 W 116th Avenue, Westminster, Colorado 80234, telephone number (303) 452-6111, Attention: Corporate Finance. In order to obtain timely delivery, security holders must request the information no later than five business days before the expiration date of the exchange offer.

This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, or the SEC. We are submitting this prospectus to holders of old bonds so that they can consider exchanging their old bonds for new bonds. You should rely only on the information contained in this prospectus and in the accompanying transmittal documents. We have not authorized any other person to provide you with any other information. If anyone provides you with different or inconsistent information, you should not rely on it. You should not assume that the information contained in this prospectus is accurate as of any date other than the date of the applicable document that contains that information. Our business, financial condition, results of operations and prospects may have changed since that date. We are not making an offer to sell nor are we soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Each broker-dealer that receives new bonds for its own account in exchange for old bonds acquired by the broker-dealer as a result of market-making or other trading activities must acknowledge that it will deliver a prospectus in connection with any resale of such new bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a participating broker-dealer in connection with resales of new bonds received in exchange for old bonds. For a period of up to 90 days following the completion of the exchange offer, we will make this prospectus, as amended or supplemented, available to any such broker-dealer that requests copies of this prospectus in the letter of transmittal for use in connection with any such resale. See “Plan of Distribution.”

Forward-looking Statements

This prospectus includes “forward-looking statements.” Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, capital expenditures, financing needs, plans or intentions relating to acquisitions, business trends and other information that is not historical information. When used in this prospectus, the words “estimates,” “expects,” “anticipates,” “projects,” “plans,” “intends,” “believes” and “forecasts” or future or conditional verbs, such as “will,” “should,” “could” or “may,” and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described under “Risk Factors” included in this prospectus. All forward-looking statements, including, without limitation, management’s examination of historical operating trends and data, are based upon our current expectations and various assumptions. Our expectations and beliefs are expressed in good faith and we believe there is a reasonable basis for them. However, we cannot assure you that management’s expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements contained in this prospectus.

Because our forward-looking statements are based on estimates and assumptions that are subject to significant business, economic and competitive uncertainties, many of which are beyond our control or are subject to change, actual results could be materially different and any or all of our forward-looking statements may turn out to be wrong. Forward-looking statements speak only as of the date made and can be affected by assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this prospectus will be important in determining future results. Consequently, we cannot assure you that our expectations or forecasts expressed in such forward-looking statements will be achieved.

Except as required by law, we undertake no obligation to publicly update any forward-looking or other statements, whether as a result of new information, future events, or otherwise. We provide a cautionary discussion of risks and uncertainties in the “Risk Factors” section in this prospectus. These are factors that we think could cause our actual results to differ materially from expected results. Other factors besides those listed here could adversely affect our business and results of operations. You should carefully consider all of these factors before participating in the exchange offer.

Summary

The following summary contains information about us and the exchange offer that we believe is important. You should read this entire prospectus, including our financial statements and the accompanying notes, for a complete understanding of us and the exchange offer. In this prospectus, the words “we”, “us”, “our”, “Association” and “Tri-State” refer to Tri-State Generation and Transmission Association, Inc. and, in the case of financial information presented under Generally Accepted Accounting Principles, or GAAP, with our consolidated subsidiaries.

ABOUT TRI-STATE

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 supply wholesale electric power to our 44 member distribution systems, or 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. For the three months ended March 31, 2016, we sold 3.8 million megawatt hours, or MWhs, to our Members and 555,085 MWhs to non-members. In 2015, we sold 15.8 million MWhs to our Members and 2.0 million MWhs to non-members. Total revenue from electric sales was \$301.9 million for the three months ended March 31, 2016 and \$1.2 billion for 2015.

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 customers (residential and business) within their designated service territories. We are subject to federal and state corporate income taxation, but, as a cooperative, we are allowed a tax exclusion for patronage sourced margins that we allocate to our Members.

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 which obligate each Member to purchase 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 March 31, 2016, 16 Members have enrolled in this program with capacity totaling approximately 83 megawatts, or MWs.

Power Supply and Transmission

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and 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.

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.

Financial Ratios and Calculations

Equity to Capitalization Ratio

Our 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 (the “Master Trustee”), as supplemented, modified and amended, or the Master Indenture, requires us to maintain an Equity to Capitalization Ratio (as defined in our Master Indenture and as below described, “ECR”) at the end of each fiscal year of 18 percent. Pursuant to the Master Indenture, ECR is calculated based on unconsolidated Tri-State financials. 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 “Description of the Master Indenture” and Appendix A—Calculation of Financial Ratios.

Debt Service Ratio

Our Master Indenture requires us to establish rates that are reasonably expected to achieve a Debt Service Ratio (as defined in our Master Indenture and as below described, “DSR”) of at least 1.10 on an annual basis. Pursuant to the Master Indenture, DSR is calculated based on unconsolidated Tri-State financials.

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 the 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. See “Description of the Master Indenture—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations.” For the twelve months ended December 31, 2015, our DSR was 1.23. See Appendix A—Calculation of Financial Ratios.

Rate Setting

We provide electric power to our Members at rates established by our Board of Directors, or Board. Our wholesale electric service contracts with our Members provide that rates paid by our Members for the electric service we provide to them must be set at levels to produce revenues, together with revenues from all other sources, sufficient to meet our cost of operation, including reasonable reserves, to cover debt and lease payments and development of Members' equity in us.

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 Member rates to the New Mexico Public Regulation Commission, or NMPRC. 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. We provide electric power to non-members at contractual rates under long-term arrangements and at market prices in spot sale transactions.

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, electric 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.

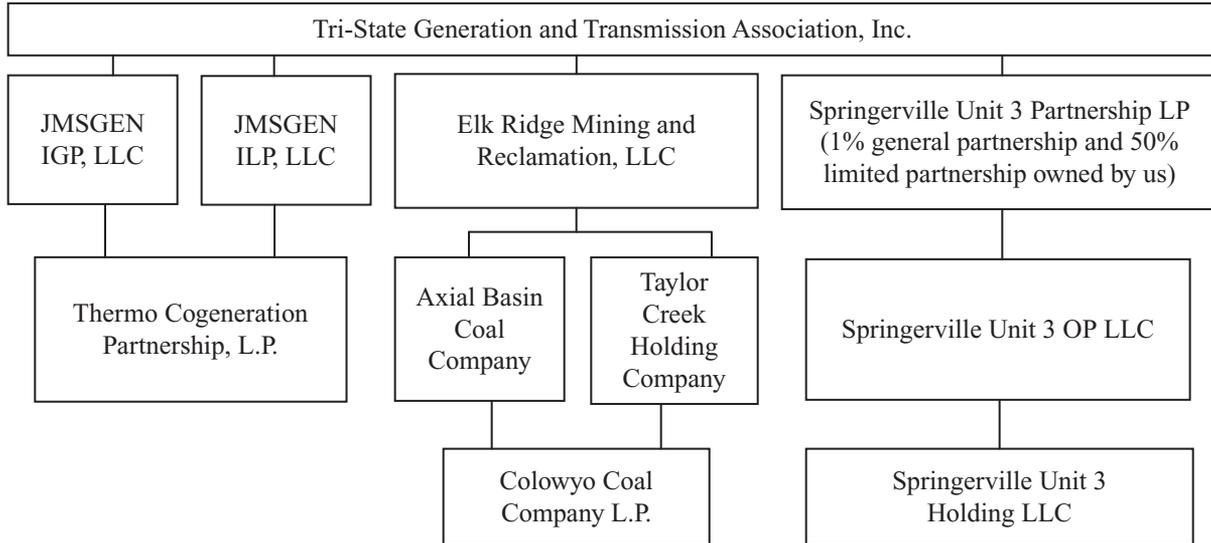
Organization and Corporate Information

We were incorporated under the laws of the State of Colorado in 1952 as a not-for-profit power supply cooperative corporation to provide wholesale electric services to our Members. 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. Information on our website is not a part of this prospectus and is not incorporated herein by reference.

We own or have a majority ownership in the following subsidiaries referenced in this prospectus: Elk Ridge Mining and Reclamation, LLC (previously known as Western Fuels-Colorado, A Limited Liability Company), or Elk Ridge; Colowyo Coal Company L.P., or Colowyo Coal; Thermo Cogeneration Partnership, L.P., or TCP; and Springerville Unit 3 Partnership LP, or Springerville Partnership. Elk Ridge is organized for the purpose of acquiring coal reserves and supplying coal to us, and is the owner and operator of the New Horizon Mine near Nucla, Colorado. Elk Ridge also owns Colowyo Coal, which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. TCP is the owner of the J.M. Shafer Generation Station, a combined cycle natural gas

generating facility located near Fort Lupton, Colorado. Springerville Partnership is the owner of Springerville Generating Station Unit 3, or Springerville Unit 3, a 416 MW coal-fired generating unit that is part of a four unit coal-based facility located in east-central Arizona. We also own or have majority ownership in several other non-material entities.

The following chart depicts our organization structure:



The Exchange Offer

- The Offering of the Old Bonds** We sold the old bonds on May 23, 2016 to Merrill Lynch, Pierce, Fenner & Smith, Incorporated, U.S Bancorp Investments, Inc., and Wells Fargo Securities, LLC, and certain other initial purchasers pursuant to a purchase agreement among us, and Merrill Lynch, Pierce, Fenner & Smith, Incorporated, U.S. Bancorp Investments, Inc., and Wells Fargo Securities, LLC, as representatives of the initial purchasers, dated May 16, 2016. We refer to Merrill Lynch, Pierce, Fenner & Smith, Incorporated, U.S. Bancorp Investments, Inc., and Wells Fargo Securities, LLC and the other initial purchasers as the “initial purchasers”. The initial purchasers subsequently resold the old bonds to qualified institutional buyers under Rule 144A as promulgated under the Securities Act of 1933, as amended, or the Securities Act.
- Registration Rights Agreement** In connection with the issuance of the old bonds, we entered into a registration rights agreement with Merrill Lynch, Pierce, Fenner & Smith, Incorporated, U.S. Bancorp Investments, Inc., and Wells Fargo Securities, LLC on behalf of itself and the initial purchasers, which obligates us to file a registration statement with the SEC within 90 days after the issue date of the old bonds and to use our commercially reasonable efforts to cause the registration statement to be declared effective under the Securities Act within 150 days after the issue date of the old bonds and to commence the exchange offer promptly after the declaration of effectiveness. The exchange offer is intended to satisfy certain of our obligations under the registration rights agreement. After the exchange offer is completed, you will no longer be entitled to any exchange or registration rights with respect to your old bonds, except under certain limited circumstances pursuant to the registration rights agreement.
- The Exchange Offer** We are offering to exchange the new bonds, which have been registered under the Securities Act, for your old bonds, which were issued on May 23, 2016 in the initial offering. In order to be exchanged, an old bond must be validly tendered and accepted. All old bonds that are validly tendered and not validly withdrawn by the expiration date of the exchange offer will be exchanged. We will issue new bonds promptly after the expiration of the exchange offer.
- Expiration Date** The exchange offer will expire at 5:00 p.m., New York City time, on _____, 2016, unless we decide to extend the expiration date.
- Exchange Agent** We have appointed Wells Fargo Bank, National Association as our exchange agent for the exchange offer. You can find the address and telephone number of the exchange agent under “The Exchange Offer—Exchange agent.”

Conditions to the Exchange Offer . . . The exchange offer is subject to customary conditions, which we may, but are not required to, waive. Please see “The Exchange Offer—Conditions to the exchange offer” for more information regarding the conditions to the exchange offer. We reserve the right, in our sole discretion, to waive any and all conditions to the exchange offer on or prior to the expiration date of the exchange offer.

Procedures for Tendering Old Bonds . Unless you comply with the procedures described below under “The Exchange Offer—Procedures for tendering old bonds—Guaranteed delivery,” you must do one of the following on or prior to the expiration date of the exchange offer to participate in the exchange offer:

- tender your old bonds by sending the certificates for your old bonds, in proper form for transfer, a properly completed and duly executed letter of transmittal with the required signature guarantee and all other documents required by the letter of transmittal to Wells Fargo Bank, National Association, as exchange agent, at the address set forth in this prospectus, and such old bonds must be received by the exchange agent prior to the expiration of the exchange offer; or
- tender your old bonds by using the book-entry transfer procedures described in “The Exchange Offer—Procedures for tendering old bonds—Book-entry delivery procedures” and transmitting a properly completed and duly executed letter of transmittal with the required signature guarantee, or an agent’s message instead of the letter of transmittal, to the exchange agent. In order for a book-entry transfer to constitute a valid tender of your old bonds in the exchange offer, Wells Fargo Bank National Association, as registrar and exchange agent, must receive a confirmation of book-entry transfer of your old bonds into the exchange agent’s account at The Depository Trust Company prior to the expiration of the exchange offer.

Guaranteed Delivery Procedures If you are a registered holder of old bonds and wish to tender your old bonds in the exchange offer, but your old bonds are not immediately available, time will not permit your old bonds or other required documents to be received by the exchange agent before the expiration of the exchange offer or the procedures for book-entry transfer cannot be completed prior to the expiration of the exchange offer, then you may tender your old bonds by following the procedures described below under “The Exchange Offer—Procedures for tendering old bonds—Guaranteed delivery.”

Special Procedures for Beneficial

Owners If you are a beneficial owner whose old bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your old bonds in the exchange offer, you should promptly contact the person in whose name your old bonds are registered and instruct that person to tender on your behalf the old bonds prior to the expiration of the exchange offer.

If you wish to tender in the exchange offer on your own behalf, prior to completing and executing the letter of transmittal and delivering the certificates for your old bonds, you must either make appropriate arrangements to register ownership of your old bonds in your name or obtain a properly completed bond power from the person in whose name your old bonds are registered.

Withdrawal; Non-acceptance You may withdraw any old bonds tendered in the exchange offer at any time prior to 5:00 p.m., New York City time, on _____, 2016 by sending the exchange agent written notice of withdrawal. Any old bonds tendered on or prior to the expiration date of the exchange offer that are not validly withdrawn on or prior to the expiration date of the exchange offer may not be withdrawn. If we decide for any reason not to accept any old bonds tendered for exchange or to withdraw the exchange offer, the old bonds will be returned to the registered holder at our expense promptly after the expiration or termination of the exchange offer. In the case of old bonds tendered by book-entry transfer into the exchange agent’s account at The Depository Trust Company, any withdrawn or unaccepted old bonds will be credited to the tendering holder’s account at The Depository Trust Company. For further information regarding the withdrawal of tendered old bonds, please see “The Exchange Offer—Withdrawal of tenders.”

Resales of New Bonds Based on interpretations by the staff of the SEC, as set forth in no-action letters issued to third parties, we believe that the new bonds you receive in the exchange offer may be offered for resale, resold or otherwise transferred by you without compliance with the registration and prospectus delivery provisions of the Securities Act so long as certain conditions are met. See “The Exchange Offer—Purpose and effects of the exchange offer” for more information regarding resales.

Consequences of Not Exchanging

your Old Bonds

If you do not exchange your old bonds in the exchange offer, you will no longer be able to require us to register your old bonds under the Securities Act pursuant to the registration rights agreement except in the limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer your old bonds unless we have registered the old bonds under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act and applicable state securities laws. Other than in connection with the exchange offer, or as otherwise required under certain limited circumstances pursuant to the terms of the registration rights agreement, we do not currently anticipate that we will register the old bonds under the Securities Act.

For more information regarding the consequences of not tendering your old bonds, please see “The Exchange Offer—Consequences of failure to exchange.”

U.S. Federal Income Tax

Considerations

The exchange of old bonds for new bonds in the exchange offer will not be a taxable exchange for U.S. federal income tax purposes. Please see “Material U.S. Federal Income Tax Consequences” for more information.

Use of Proceeds

The exchange offer is being made solely to satisfy certain of our obligations under the registration rights agreement, and we will not receive any cash proceeds from the issuance of the new bonds. See “Use of Proceeds.”

Fees and Expenses

We will pay all of our expenses incident to the exchange offer.

Additional Documentation; Further

Information; Assistance

Any questions or requests for assistance or additional documentation regarding the exchange offer may be directed to the exchange agent. Beneficial owners may also contact their custodian for assistance concerning the exchange offer.

The New Bonds

The terms of the new bonds are identical in all material respects to the terms of the old bonds, except that the transfer restrictions, registration rights and additional interest provisions relating to the old bonds do not apply to the new bonds. The new bonds represent the same debt as the old bonds for which they are being exchanged. Both the old bonds and the new bonds are governed by the same indenture. References to the bonds in this prospectus include both the old bonds and the new bonds, unless otherwise specified or the context otherwise requires.

Issuer	Tri-State Generation and Transmission Association, Inc.
Securities Offered	\$250.0 million aggregate principal amount of 4.25% First Mortgage Bonds, Series 2016A, due 2046.
Interest Rate	The new 2016A bonds will bear interest at a rate of 4.25% per annum. See “Description of the Bonds—Interest.”
Maturity Date	June 1, 2046.
Interest Payment Dates	June 1 and December 1, beginning December 1, 2016. Interest on the bonds accrued from May 23, 2016.
Master Indenture and Ranking	<p>Our obligation to pay principal, premium, if any, and interest on the new bonds will be secured by the Master Indenture. See “Description of the Master Indenture.”</p> <p>The new bonds will be our senior secured obligations and will be secured equally and ratably with all other secured obligations issued under the Master Indenture by a lien on substantially all of our tangible assets and certain of our intangible assets. See “Description of the Master Indenture—Security.”</p> <p>The Master Indenture permits us to incur additional secured obligations subject to meeting certain historic and pro forma DSR requirements set forth in the Master Indenture. See “Description of the Master Indenture—Security” and “—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations.”</p>

Optional Redemption	We may redeem the new bonds, in whole or in part, at any time before December 1, 2045 (which is the date that is six months prior to the maturity date for the bonds) by paying the “make-whole” redemption price plus accrued and unpaid interest, if any, on such bonds, to, but excluding, the redemption date. The new bonds may be redeemed at par on or after December 1, 2045 (which is the date that is six months prior to the maturity date for the bonds) plus accrued and unpaid interest, if any, on such bonds, to, but excluding, the redemption date. See “Description of the Bonds—Redemption.”
Events of Default	If an event of default occurs under the Master Indenture, the principal amount of the new bonds then outstanding, together with any accrued interest, may be declared immediately due and payable, except that upon the occurrence of certain bankruptcy related events of default under the Master Indenture, such principal and interest will become immediately due and payable without any such declaration. See “Description of the Master Indenture—Events of Defaults and Remedies.”
Certain Covenants	<p>The Master Indenture obligates us to establish and collect rates and other charges at levels which, together with other revenues, are reasonably expected to cause our DSR to be at least 1.10 on an annual basis. Under the Master Indenture, we are also required to maintain an ECR at the end of each fiscal year of at least 18 percent. See “Description of the Master Indenture—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations” and “—ECR Covenant.” See also “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Master Indenture.”</p> <p>In addition, the Master Indenture places certain restrictions on our ability to, among other things, create liens on or dispose of certain property subject to the lien thereof, engage in consolidations or mergers, issue subordinated secured debt and unsecured debt, and retire patronage capital to our Members. See “Description of the Master Indenture.”</p>

Form and Denomination	The new bonds will be represented by one or more global bonds issued in fully registered form that, when issued, will be registered in the name of Cede & Co., as registered owner and as nominee for DTC. Purchases and transfers of beneficial interests in the global bonds will be made in book-entry form. Purchases of new bonds or beneficial interests in the new bonds may be made in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.
Master Trustee, Registrar and Paying Agent	Wells Fargo Bank, National Association
Absence of Public Market for the New Bonds	The new bonds generally will be freely transferable but will also be a new issue of securities for which there is currently no established trading market. We do not intend to apply for a listing of the new bonds on any securities exchange or an automated dealer quotation system. Accordingly, there can be no assurance as to the development or liquidity of any market for the new bonds.
Risk Factors	You should carefully consider all of the information contained in this prospectus and, in particular, you should evaluate the specific factors under “Risk Factors”.
Governing Law	The new bonds and certain other documents related to the issuance of the new bonds will be governed by the laws of the State of New York; the Master Indenture is governed by and construed in accordance with the laws of the State of Colorado and applicable federal law (except to the extent the law of another jurisdiction is mandatorily applicable and to the extent that laws relating to perfection, priority and enforcement and related remedies may be governed by the laws of another state, and except that the rights and obligations of the Master Trustee are governed by the laws of the jurisdiction in which the Master Trustee’s corporate trust office is located).

Summary Consolidated Financial Data

The following tables set forth a summary of our consolidated financial data as of and for the periods indicated. The summary consolidated financial data as of March 31, 2016 and for the three months ended March 31, 2016 and 2015 were derived from our unaudited consolidated financial statements, included elsewhere in this prospectus. The unaudited consolidated financial statements have been prepared on the same basis as the audited consolidated financial statements and, in management's opinion, include all adjustments, consisting of only normal recurring adjustments, necessary for a fair presentation of financial position and the results of operation for these periods. The financial data presented for the three months ended March 31, 2016 are not necessarily indicative of the results that may be expected for the year ended December 31, 2016 or any future period.

The summary consolidated financial data as of December 31, 2015 and 2014 and for the three years ended December 31, 2015 were derived from our audited consolidated financial statements, included elsewhere in this prospectus. The summary consolidated financial data as of December 31, 2013, 2012 and 2011 and for the two years ended December 31, 2012 were derived from our audited financial statements not included in this prospectus. 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 and unaudited financial statements, including the notes to such financial statements contained elsewhere in this prospectus.

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
Selected Income Statement Data							
Operating revenues	\$ 323,462	\$ 328,391	\$ 1,335,448	\$ 1,395,091	\$ 1,341,163	\$ 1,291,832	\$ 1,184,431
Operating expenses	(277,083)	(279,007)	(1,157,479)	(1,213,214)	(1,152,575)	(1,125,617)	(1,025,676)
Operating margins	46,379	49,384	177,969	181,877	188,588	166,215	158,755
Interest expense	(35,420)	(36,163)	(142,570)	(142,357)	(149,463)	(151,905)	(155,022)
Net margins attributable to the Association	17,533	20,126	53,413	64,236	72,912	52,795	69,934

	As of March 31,		As of December 31,				
	2016	2015	2015	2014	2013	2012	2011
Balance Sheet Data							
Total assets	\$4,835,539	\$4,823,047	\$4,654,136	\$4,692,584	\$4,561,680	\$4,572,660	
Electric plant, in service, less accumulated depreciation and amortization	3,257,918	3,245,786	3,064,063	2,941,860	2,926,700	2,819,499	
Construction work in process	212,328	216,279	206,097	231,374	152,355	183,178	
Long term debt	3,275,624	3,273,538	3,145,246	3,069,218	3,049,481	3,093,839	
Patronage capital equity	969,615	952,082	908,669	865,379	802,467	759,672	
Accumulated other comprehensive income (loss)	545	589	(828)	3,335	3,415	3,663	
Noncontrolling interest	108,750	108,757	109,302	110,740	113,027	116,120	
Total Capitalization	\$4,354,534	\$4,334,966	\$4,162,389	\$4,048,672	\$3,968,390	\$3,973,294	

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
Other Data							
Ratio of Earnings to Fixed Charges	1.36	1.45	1.25	1.32	1.37	1.22	1.33
MWhs Sold							
—Member	3,829,433	3,783,686	15,780,670	15,426,603	15,313,487	15,717,468	15,421,227
—Nonmember	555,085	591,324	2,026,525	3,272,140	3,316,487	3,010,314	3,976,884

Risk Factors

Before participating in the exchange offer, you should carefully consider the various risks of an investment in the new bonds, including those described below, together with all of the other information included in this prospectus. Our business, financial condition or results of operations could be materially adversely affected by any of these risks. These risks also include forward-looking statements, and our actual results may differ substantially from those discussed in these forward-looking statements. See “Forward-looking Statements.”

Risks Related to Our Business Operations

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 Environmental Protection Agency, or 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, a substantial percentage of which is generated by coal-fired facilities. More stringent standards may require us to modify the design or operation of existing facilities or purchase emission allowances. These actions may result in substantial increases in the cost of electricity to our Members.

In 2015, the EPA finalized emission limits and emission guidelines of 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 Colorado Public Utilities Commission 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 March 31, 2016, we had total debt outstanding of approximately \$3.4 billion, of which approximately \$2.9 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 March 31, 2016, we had \$568 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 2015 data, industrial and large commercial customers account for approximately 36 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 18.5 percent of the aggregate retail electric energy sales of our Members, based on the same 2015 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 North American Electric Reliability Corporation, or 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 Federal Power Act, or 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 Renewable Portfolio Standard, or 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 Western Area Power Administration, or WAPA (a power marketing agency of the U.S. Department of Energy), and Basin Electric Power Cooperative, or Basin, consisting of approximately 15.2 percent and 14.9 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.

Risks Related to the New Bonds

If an active trading market does not develop for the new bonds, you may be unable to sell the new bonds or to sell them at a price you deem sufficient.

The new bonds will be new securities for which there is no established trading market. We do not intend to apply for listing of the new bonds on any securities exchange or to arrange for the bonds to be quoted on any automated quotation system. Any market making activity, if initiated, may be discontinued at any time, for any reason, without notice. In addition, such market making activities may be limited during the exchange offer or while the effectiveness of a shelf registration statement is pending. As a result, we cannot provide any assurance as to:

- the liquidity of any trading market that may develop for the new bonds;
- the ability of holders to sell their new bonds; or
- the price at which holders would be able to sell their new bonds.

Even if a trading market develops, the new bonds may trade at higher or lower prices than their principal amount or purchase price, depending on many factors, including:

- prevailing interest rates;
- the number of holders of the new bonds;
- the interest of securities dealers in making a market for the new bonds; and
- our operating results.

If a market for the new bonds does not develop, purchasers may be unable to resell the new bonds for an extended period of time. Consequently, a holder of the new bonds may not be able to liquidate

its investment readily, and the new bonds may not be readily accepted as collateral for loans. In addition, market-making activities will be subject to restrictions of the Securities Act and the Exchange Act.

The market price of the new bonds may fluctuate.

Any material differences between our actual results and the historical results contained in our annual and quarterly financial reports could have a significant adverse impact on the price of the new bonds, assuming a market for the new bonds develops. If such a market develops, prevailing interest rates may cause the new bonds to trade at higher or lower prices than their principal amount or purchase price and any downgrade of our credit ratings could have a significant adverse impact on the price of the new bonds.

Use of Proceeds

The exchange offer is intended to satisfy certain of our obligations under the registration rights agreement. We will not receive any cash proceeds from the issuance of the new bonds and have agreed to pay the expenses of the exchange offer, other than certain taxes. In consideration for issuing the new bonds as contemplated in this prospectus, we will receive in exchange old bonds in a like principal amount. The form and terms of the new bonds are identical in all material respects to the form and terms of the old bonds, except as otherwise described herein under “The exchange offer—Terms of the exchange offer.” The old bonds surrendered in exchange for the new bonds will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new bonds will not result in any change in our outstanding indebtedness.

Capitalization

The following table sets forth our capitalization as of March 31, 2016 on an actual basis and on an as adjusted basis after giving effect to the issuance of the bonds in the initial offering. You should read the information in this table in conjunction with “Selected Consolidated Financial Data” and Tri-State’s audited and unaudited consolidated financial statements and the notes to those financial statements, all included elsewhere in this prospectus. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity.”

	As of March 31, 2016	
	(Actual)	(As Adjusted)
	(In thousands)	
First Mortgage Bonds, Series 2016A	\$ —	\$ 250,000
3.66% to 8.08% CFC due through 2028	85,314	85,314
Variable rate CFC due through 2049	102,853	102,853
2.63% to 6.17% CoBank due through 2042	275,601	275,601
Variable rate CoBank due through 2044	102,220	102,220
First Mortgage Bonds, Series 2014E-1	250,000	250,000
First Mortgage Bonds, Series 2014E-2	250,000	250,000
Series 2010A First Mortgage Bonds	500,000	500,000
Series 2014B First Mortgage Bonds, Tranche 1, 3.90%, due through 2033 . . .	180,000	180,000
Series 2014B First Mortgage Bonds, Tranche 2, 4.30%, due through 2039 . . .	20,000	20,000
Series 2014B First Mortgage Bonds, Tranche 3, 4.45%, due through 2045 . . .	550,000	550,000
Series 2009C First Mortgage Bonds, Tranche 1, 6.00%, due through 2019 . . .	108,571	108,571
Series 2009C First Mortgage Bonds, Tranche 2, 6.31%, due through 2021 . . .	110,000	110,000
Revolving Credit Agreement	316,000	92,000
5% Pollution control revenue bonds, due through 2017	10,815	10,815
Variable rate pollution control revenue bonds, due 2036	46,800	46,800
Springerville Bonds, Series A, 6.04%, due through 2018	52,994	52,994
Springerville Bonds, Series B, 7.14%, due through 2033	405,000	405,000
Colowyo Bonds*, 10.19%, due through 2016	7,693	7,693
Other	1,570	1,570
Total Debt	\$3,375,431	\$3,401,431
Less debt issuance costs	(20,731)	(23,224)
Less debt discounts	(8,698)	(10,713)
Plus debt premiums	22,513	22,513
Total debt adjusted for discounts, premiums, and debt issuance costs	\$3,368,515	\$3,390,007
Less current maturities	(92,891)	(92,891)
Total Long-term Indebtedness	\$3,275,624	\$3,297,116
Total Patronage Capital Equity	969,615	969,615
Accumulated Other Comprehensive Income	545	545
Noncontrolling Interest	108,750	108,750
Total Capitalization	\$4,354,534	\$4,376,026

* This debt has been economically defeased.

Selected Consolidated Financial Data

The following tables set forth our selected consolidated financial data as of and for the periods indicated. The selected consolidated financial data as of March 31, 2016 and for the three months ended March 31, 2016 and 2015 were derived from our unaudited consolidated financial statements, included elsewhere in this prospectus. The unaudited consolidated financial statements have been prepared on the same basis as the audited consolidated financial statements and, in management's opinion, include all adjustments, consisting of only normal recurring adjustments, necessary for a fair presentation of financial position and the results of operation for these periods. The financial data presented for the three months ended March 31, 2016 are not necessarily indicative of the results that may be expected for the year ended December 31, 2016 or any future period.

The selected consolidated financial data as of December 31, 2015 and 2014 and for the three years ended December 31, 2015 were derived from our audited consolidated financial statements, included elsewhere in this prospectus. The selected consolidated financial data as of December 31, 2013, 2012 and 2011 and for the two years ended December 31, 2012 were derived from our audited financial statements not included in this prospectus. This selected consolidated financial data is qualified in its entirety by and should be read in conjunction with the more detailed information and the audited and

unaudited financial statements, including the notes to such financial statements contained elsewhere in this prospectus.

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
Income Statement Data:							
Operating Revenue							
Member electric sales	\$271,769	\$267,539	\$1,125,699	\$1,101,471	\$1,091,103	\$1,067,085	\$1,007,993
Non-member electric sales	30,122	35,063	120,234	197,497	172,102	162,694	152,806
Other	21,571	25,789	89,515	96,123	77,958	62,053	23,632
	323,462	328,391	1,335,448	1,395,091	1,341,163	1,291,832	1,184,431
Operating Expenses							
Purchased Power	71,035	73,137	305,045	327,445	322,059	310,293	273,287
Fuel	60,990	61,275	231,537	293,033	287,647	273,169	265,917
Production	50,982	53,520	235,398	229,933	209,816	213,674	187,981
Transmission	36,460	37,099	153,443	145,396	138,684	136,853	136,825
General and administrative	5,110	6,151	24,708	28,591	24,325	22,810	18,930
Depreciation, amortization and depletion	38,903	34,978	152,718	128,712	121,818	124,861	105,793
Coal mining	8,273	8,827	36,130	40,849	29,889	25,027	2,562
Other	5,330	4,020	18,500	19,255	18,337	18,930	34,381
	277,083	279,007	1,157,479	1,213,214	1,152,575	1,125,617	1,025,676
Operating Margins	46,379	49,384	177,969	181,877	188,588	166,215	158,755
Other Income							
Interest Income	1,074	1,083	4,355	11,076	17,288	24,035	27,076
Capital credits from cooperatives	4,511	4,294	9,189	8,684	10,922	7,845	7,167
Other income	1,041	1,348	3,981	3,573	3,344	3,563	28,135
	6,626	6,725	17,525	23,333	31,554	35,443	62,378
Interest expense, net of amounts capitalized . . .	35,420	36,163	142,570	142,357	149,463	151,905	155,022
Income taxes	—	—	—	—	—	—	10
Net margins including noncontrolling interest .	17,585	19,946	52,924	62,853	70,679	49,753	66,121
Net (income) loss attributable to noncontrolling interest .	(52)	180	489	1,383	2,233	3,042	3,813
Net margins attributable to Tri-State	\$ 17,533	\$ 20,126	\$ 53,413	\$ 64,236	\$ 72,912	\$ 52,795	\$ 69,934

	As of March 31,		As of December 31,			
	2016	2015	2014	2013	2012	2011
Balance Sheet Data						
Total assets	\$4,835,539	\$4,823,047	\$4,654,136	\$4,692,584	\$4,561,680	\$4,572,660
Electric plant, in service, less accumulated depreciation and amortization	3,257,918	3,245,786	3,064,063	2,941,860	2,926,700	2,819,499
Construction work in process	212,328	216,279	206,097	231,374	152,355	183,178
Long term debt	3,275,624	3,273,538	3,145,246	3,069,218	3,049,481	3,093,839
Patronage capital equity	969,615	952,082	908,669	865,379	802,467	759,672
Accumulated other comprehensive income (loss)	545	589	(828)	3,335	3,415	3,663
Noncontrolling interest	108,750	108,757	109,302	110,740	113,027	116,120
Total Capitalization	\$4,354,534	\$4,334,966	\$4,162,389	\$4,048,672	\$3,968,390	\$3,973,294

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
Other Data							
Ratio of Earnings to Fixed Charges	1.36	1.45	1.25	1.32	1.37	1.22	1.33
MWhs Sold							
—Member	3,829,433	3,783,686	15,780,670	15,426,603	15,313,487	15,717,468	15,421,227
—Nonmember	555,085	591,324	2,026,525	3,272,140	3,316,487	3,010,314	3,976,884

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 627,000 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 sold 4.4 million MWhs for the three months ended March 31, 2016, of which 87 percent was to Members. Total revenue from electric sales was \$301.9 million for the three months ended March 31, 2016, 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 for 2015) and extending through 2040 for the remaining two Members (Kit Carson Electric Cooperative, Inc., or Kit Carson, and Delta Montrose Electric Association, or DMEA, which constitute approximately 5 percent of our revenue from Member sales for 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 March 31, 2016, 16 Members have enrolled in this program with capacity totaling approximately 83 megawatts.

Kit Carson has communicated its intent to withdraw from membership in us and our Board has approved such withdrawal from membership, subject to execution of a binding agreement and compliance with certain conditions, including payment of an early termination fee. In March 2016, we executed a non-binding letter of intent with Kit Carson providing the principal terms for Kit Carson's withdrawal. We are negotiating with Kit Carson on a binding agreement providing for Kit Carson's withdrawal from membership in us and termination of the wholesale electric service contract with Kit Carson. For the three most recent fiscal years, Kit Carson constituted an average of approximately 2 percent of our revenue from Member sales.

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 provide the Board with discretion on order of retirement. As of March 31, 2016, patronage capital equity was \$969.6 million.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission 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 stations. Additionally, we transmit power to our Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers.

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 evaluates whether to retire 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. 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 kilowatt hour, or 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, 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.

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 proceedings pending in New Mexico regarding efforts by the NMPRC related to our prior wholesale rates payable by our Members.

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 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. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our A-38 wholesale rate which was scheduled to become effective on January 1, 2014. Four Members filed protests with the NMPRC challenging the A-38 rate. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015 and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider was applied in conjunction with 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. 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 March 31, 2016, we had approximately \$2.9 billion of secured indebtedness outstanding under the Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under the 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.

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.

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

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. 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.

Three months ended March 31, 2016 compared to three months ended March 31, 2015

Operating Revenues

Member electric sales increased 45,747 MWhs to 3,829,433 MWhs for the three months ended March 31, 2016 compared to 3,783,686 MWhs for the same period in 2015. The increase in MWhs sold in 2016 resulted in an increase of \$4.3 million in Member electric sales revenue to \$271.8 million for the three months ended March 31, 2016 compared to \$267.5 million for the same period in 2015. The increase in revenue was primarily due to an increase in the Members' sales to oil and gas customers.

Non-member electric sales decreased 36,239 MWhs, or 6.1 percent, to 555,085 MWhs for the three months ended March 31, 2016 compared to 591,324 MWhs for the same period in 2015. Non-member electric sales revenue decreased \$5.0 million, or 14.2 percent, to \$30.1 million for the three months ended March 31, 2016 compared to \$35.1 million for the same period in 2015. The decrease in non-member electric sales revenue was due to lower long-term firm energy sales to non-members of 94,323 MWhs with revenues of \$4.8 million resulting from a decrease in demand for energy under these contracts due to the availability of lower priced market energy. The decrease was partially offset by an increase of 40,316 MWhs in short-term energy sales with an associated increase in revenues of \$404,000.

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. Other revenue decreased \$4.2 million, or 16.3 percent, to \$21.6 million for the three months ended March 31, 2016 compared to \$25.8 million for the same period in 2015. The decrease in other operating revenue was primarily due to a decrease in coal sales to other joint owners in the Yampa Project and a decrease in wheeling revenue, and steam and water revenue.

Operating Expenses

Purchased power increased 10,301 MWhs to 1,653,252 MWhs for the three months ended March 31, 2016 compared to 1,642,951 MWhs for the same period in 2015. Despite the increase in

MWhs purchased, purchased power expense decreased \$2.1 million to \$71.0 million for the three months ended March 31, 2016 compared to \$73.1 million for the same period in 2015 due to a 3.9 percent decrease in the average cost per MWh of purchased power resulting from lower market prices for power.

Depreciation and amortization expense increased \$3.9 million, or 11.2 percent, to \$38.9 million for the three months ended March 31, 2016 compared to \$35.0 million for the same period in 2015. The increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. In addition, depreciation expense increased (beginning in the third quarter 2015) at the San Juan Generating Station Unit 3 due to a shortened economic life associated with the anticipated December 31, 2017 retirement date of the unit.

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 Railway Company, or 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 Generating Station Unit 3, Escalante Generating 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 United States Department of Agriculture, Rural Utilities Service, or 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 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. 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 Federal Financing Bank 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

March 31, 2016 compared to December 31, 2015

Assets

Cash and cash equivalents increased \$16.1 million, or 11.1 percent, to \$160.7 million as of March 31, 2016 compared to \$144.6 million as of December 31, 2015. The increase in cash and cash equivalents was primarily due to \$45 million of proceeds from issuance of debt from our secured revolving credit facility, or Revolving Credit Agreement, and an increase in cash collected from Member accounts receivable, partially offset by capital expenditures of \$40.3 million, and debt payments of \$41.2 million (of which \$37.0 million was for a Springerville certificate payment).

Deposits and advances increased \$6.8 million, or 31.3 percent, to \$28.5 million as of March 31, 2016 compared to \$21.7 million as of December 31, 2015. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These payments are being amortized to expense over the term of the related insurance, membership or license period.

Coal inventory decreased \$6.2 million, or 10.5 percent, to \$53.1 million as of March 31, 2016 compared to \$59.3 million as of December 31, 2015. The decrease in coal inventory was primarily due to a \$5.7 million decrease in coal inventory at the Craig Generating Station and a \$1.8 million decrease in coal inventory at the Springerville Unit 3 due to coal supply planning at each station. These decreases were partially offset by a \$2.2 million increase in coal inventory at our Escalante Generating Station due to lower generation.

Equity and Liabilities

Patronage capital equity increased \$17.5 million to \$969.6 million as of March 31, 2016 compared to \$952.1 million as of December 31, 2015. The increase was due to a margin attributable to us of \$17.5 million for the three months ended March 31, 2016.

Accounts payable decreased \$13.8 million, or 14.4 percent, to \$82.3 million as of March 31, 2016 compared to \$96.1 million as of December 31, 2015. The decrease was primarily due to the timing and payment of trade payables.

Accrued interest increased \$14.4 million, or 41.9 percent, to \$48.7 million as of March 31, 2016 compared to \$34.3 million as of December 31, 2015. The increase was primarily due to the timing of interest payments related to certain obligations that are due during the second quarter of 2016.

December 31, 2015 compared to December 31, 2014

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 Coal Contract Receivable Collateralized Bonds, or 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 Generating 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 Generating 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 March 31, 2016 is as follows:

	<u>(In thousands)</u>
Cash	\$160,743
Revolving Credit Agreement Availability	<u>386,258</u>
Total Liquid Funds Available	<u>\$547,001</u>

Our 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 March 31, 2016. The Revolving Credit Agreement is secured under the Master Indenture and has a term extending through July 26, 2019. We had outstanding borrowings of \$316 million and \$271 million at March 31, 2016 and December 31, 2015, respectively, and an issued letter of credit for the Moffat County, CO Pollution Control Bonds in the principal amount of \$46.8 million plus accrued interest

supported by the Revolving Credit Agreement. 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 ½ 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. As of March 31, 2016, we have \$386 million in availability under the Revolving Credit Agreement.

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

Under our commercial paper program, which we began in May 2016, we are authorized to issue commercial paper in amounts that do not exceed the commercial paper sublimit, which is the lesser of \$500 million or the amount available under the Revolving Credit Agreement, thereby providing 100% dedicated support for any commercial paper outstanding.

Between projected cash on hand, our commercial paper program, 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.

March 31, 2016 compared to March 31, 2015

Operating activities. Net cash provided by operating activities was \$61.2 million for the three months ended March 31, 2016 comprised primarily of net margins of \$17.6 million, non-cash depreciation, amortization, and depletion of \$38.9 million, other non-cash amortization of \$3.6 million and an increase in cash collected from Member accounts receivable resulting from increased loads. Operating activities were also impacted by a \$15.7 million decrease in accounts payable and accrued expenses related to the timing of the payment of trade payables and an increase in accrued interest of \$14.4 million due to the timing of interest payments related to certain obligations that are due during the second quarter of 2016.

Investing activities. Net cash used in investing activities was \$45.2 million for the three months ended March 31, 2016 comprised primarily of capital expenditures for generation and transmission improvements and system upgrades.

Financing activities. Net cash provided by financing activities was \$117,000 for the three months ended March 31, 2016 comprised primarily of a \$45.0 million draw on our Revolving Credit Agreement offset by payments of long-term debt of \$41.2 million (principally a \$37.0 million payment on the Springerville certificates).

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 National Rural Utilities Cooperative Finance Corporation, or 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 estimate 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 facilities and existing and new transmission facilities going forward depend on a variety of factors, including Member load growth, availability of necessary permits, 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 March 31, 2016, we have incurred capital expenditures of approximately \$88.0 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 as our Board has not yet made a decision to proceed with the construction of this project including our option to acquire the development rights.

Outstanding Obligations

As of March 31, 2016, we had \$3.4 billion in outstanding obligations, including \$2.9 billion secured on a parity basis by our Master Indenture, two unsecured loan agreements totaling \$54 million, the Springerville certificates totaling \$458 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 May 23, 2016, we issued our First Mortgage Bonds, Series 2016A pursuant to Rule 144A under the Securities Act with an aggregate principal amount of \$250 million. The Series 2016A Bonds mature on June 1, 2046 and bear interest at a rate of 4.25% per annum.

We have the Revolving Credit Agreement in the amount of \$750 million expiring in 2019. We had outstanding borrowings of \$316 million at March 31, 2016. 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. As of March 31, 2016, the availability under the Revolving Credit Agreement was \$386 million. Subsequent to March 31, 2016, we borrowed an additional \$17 million under the Revolving Credit Agreement and utilized the proceeds from the First Mortgage Bonds, Series 2016A to repay \$241 million of outstanding indebtedness under the Revolving Credit Agreement.

Contractual Commitments

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our owned and leased generating and transmission facilities, the financing of our operations and other matters. The following table summarizes our long-term contractual obligations as of December 31, 2015:

Obligations	Payments Due by Period				
	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	<u>\$6,613,540</u>	<u>\$418,244</u>	<u>\$833,174</u>	<u>\$867,618</u>	<u>\$4,494,504</u>

(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, our commercial paper program, borrowings under the Revolving Credit Agreement and the issuance of additional long-term indebtedness.

Indebtedness. As of March 31, 2016, we had approximately \$2.9 billion of debt outstanding secured on a parity basis under the Master Indenture. Our debt secured by the lien of the Master Indenture includes notes payable to CFC and CoBank, ACB, or CoBank, (with the exception of one term loan which is unsecured), 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, the pollution control revenue bonds, and amounts outstanding under the Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture. The Springerville certificates are secured only by a mortgage and lien on Springerville Generating Station Unit 3 and the Springerville lease. Subsequent to March 31, 2016, we issued under our Master Indenture \$250 million of First Mortgage Bonds, Series 2016A.

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.

TEP FERC Case

In 2015, Tucson Electric Power Company, or TEP, filed various non-conforming point-to-point transmission services agreements with the Federal Energy Regulatory Commission, or FERC, including transmission services agreements between TEP and us. FERC, in 2015, ordered TEP to refund the time value of monies for a certain period of time with regard to these transmission services agreements between TEP and us. TEP subsequently requested rehearing with FERC. On April 21, 2016, FERC denied TEP's request for rehearing regarding these transmission services agreements between TEP and us and ordered TEP to make a time value refund within 30 days of the date of the order, including an amount up to \$12.8 million to us. On May 13, 2016, TEP filed a motion for a 30 day extension to make refunds, which was granted by FERC on May 19, 2016. TEP has stated they may appeal FERC's order.

Rating Triggers

Our current senior secured ratings are "A3 (stable outlook)" by Moody's Investors Service, Inc., or Moody's, "A (stable outlook)" by S&P Global Ratings, or S&P, and "A (stable outlook)" by Fitch Ratings, Inc., or Fitch. Our current short term ratings are "P-2 (stable outlook)" by Moody's, "A-1 (stable outlook)" by S&P, and "F-1 (stable 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.

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 are as follows:

	March 31, 2016		December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	\$3,375,431	\$3,797,978	\$3,371,679	\$3,616,946

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 March 31, 2016, we were exposed to the risk of changes in interest rates related to our \$567.9 million of variable rate debt, including \$316.0 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 March 31, 2016, the weighted average interest rate on this variable rate debt was 1.55 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 March 31, 2016, we had 16.8 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 \$5.7 million.

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures for new facilities and upgrades to our existing facilities. To mitigate the risk of rising interest rates, in April 2016, we hedged a portion of our interest rate risk by entering into a 36 month forward-starting 30 year LIBOR swap in the notional amount of \$90 million with an effective date of April 15, 2019 and a maturity date of April 15, 2049. The fixed rate on the swap is 2.355%.

Tri-State Generation and Transmission Association, Inc.

Our Business

We are 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. In 2015, we sold 17.8 million MWhs, of which 89 percent was to our Members. Total revenue from electric sales was \$1.2 billion for 2015, of which 90 percent was from Member sales. We sold 4.4 million MWhs for the three months ended March 31, 2016, of which 87 percent was to our Members. Total revenue from electric sales was \$301.9 million for the three months ended March 31, 2016, of which 90 percent was from Member sales.

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. Information on our website is not a part of this prospectus and is not incorporated herein by reference.

Including our subsidiaries, as of March 31, 2016, we employed 1,561 people, of which approximately 361 were subject to collective bargaining agreements. As of March 31, 2016, 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 purchase 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.

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

Kit Carson has communicated its intent to withdraw from membership in us and our Board has approved such withdrawal from membership, subject to execution of a binding agreement and compliance with certain conditions, including payment of an early termination fee. In March 2016, we executed a non-binding letter of intent with Kit Carson providing the principal terms for Kit Carson's withdrawal. We are negotiating with Kit Carson on a binding agreement providing for Kit Carson's withdrawal from membership in us and termination of the wholesale electric service contract with Kit Carson. For the three most recent fiscal years, Kit Carson constituted an average of approximately 2 percent of our revenue from Member sales.

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 and DMEA 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 March 31, 2016, 16 Members have enrolled in this program with capacity totaling approximately 83 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:

<u>Year</u>	<u>Members’ Peak Demand (MW)</u>	<u>Amount of Energy Sold (MWh)</u>
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, and climate and weather patterns of the service territories creates balance within our system.

Customers. Our Members’ sales of energy in 2015 were divided by customer class as follows:

<u>Customer Class</u>	<u>Percentage of MWh Sales</u>	<u>Percentage of Customers</u>
Residential	29.9%	83.0%
Large commercial	36.2	0.1
Small commercial	21.0	12.8
Irrigation	7.9	3.8
Other	5.0	0.3

From 2011 to 2015, our Members experienced an average annual compound growth rate of approximately 0.8 percent in the number of customers and an average annual compound growth rate of 1.0 percent in energy sales. In 2015, the 15 largest customers of our Members represented 18.5 percent of electric energy sales by our Members, although no single customer of our Members represented more than 4 percent of our total energy sales. These customers are primarily in the 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 2010 at approximately five customers per mile. System densities of our Members in 2015 ranged from 1.2 customers per mile to 13.2 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 Public Service Company of Colorado, or 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 April 2016. 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.

<u>Year</u>	<u>Average Member Cents/kWh Sales</u>
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 2015, our largest Member sold 2.0 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 which are identified in the table below:

<u>Name</u>	<u>Location</u>	<u>% Interest Owned or Leased</u>	<u>Fuel Used</u>	<u>Unit Rating (MW)*</u>	<u>Our Share (MW)</u>	<u>Year Installed</u>
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 Generating Station, or 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 Generating Station, or 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 Agricultural Improvement and Power District, or Salt River Project, and 100 MW of such capacity to Public Service Company of New Mexico, or PNM. We own a 51 percent equity interest (including the 1 percent general partner equity interest) in Springerville Partnership, which owns Springerville Unit 3.

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. PNM, 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.

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.

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 TCP. 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.

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.

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):

<u>Resource:</u>	<u>Summer</u>	<u>Winter</u>
	(MW)	(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. For the year ended December 31, 2015, the maximum 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.

<u>Facility Name</u>	<u>Location</u>	<u>Counterparty</u>	<u>Primary Fuel</u>	<u>Facility Rating (MW)</u>	<u>Year of Commercial Operation</u>	<u>Year of Contract Expiration</u>
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 Electric Power Corporation, or 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 March 2016, we have incurred development costs of approximately \$95 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 March 2016, 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 an agreement with PSCO for the sale of 100 MWs of capacity to PSCO through March 2017. This agreement is contingent upon the availability of capacity from Craig Station Units 1, 2, and 3, and Laramie River Generating Station Units 2 and 3. We do not expect this agreement 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 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. We also have a reciprocal one year agreement with PNM that expires May 31, 2017 to provide PNM 100 MWs of power contingent on the operation of Springerville Unit 3 and to purchase from PNM 100 MWs of power contingent on the operation of PNM’s San Juan Generating Station Unit 4.

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. The following table summarizes the sources of our coal for each of our coal-based generating facilities:

<u>Generating Station</u>	<u>Mine</u>	<u>Contract End Date</u>	<u>Annual Tonnage— Our Share (approximate)</u>
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.

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

<u>Mine</u>	<u>Location</u>	<u>% Interest Owned</u>
Colowyo 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 Western Fuels-Wyoming, Inc.. 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.

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).

	<u>Direct Flow Amount in Cubic Feet per Second (cfs)</u>	<u>Annual Appropriation (Acre Feet/Year)</u>	<u>Storage Amount (Acre Feet/Year)</u>	<u>Our Percentage</u>
Surface Water Rights				
<i>Craig Station Units 1 and 2</i>	75.3		8,310	24
<i>Craig Station Unit 3</i>	45.9		2,500	100
<i>Nucla Generating Station</i>	61.1		400	100
Underground Water Rights				
<i>Burlington Generating Station</i>		39		100
<i>Escalante Station</i>		4,397		100
<i>Knutson Generating Station</i>		32		100
<i>Pyramid Generating Station</i>		1,055		100
Contract Rights				
<i>Craig Generating Station Unit 3</i>			7,000	100
<i>J.M. Shafer Generating Station</i>		1,110		100
<i>Limon Generating Station</i>			50	100
<i>Rifle Generating Station</i>			275	100
<i>Springerville Generating Station</i>		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 Environmental Management System, or 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 (SO₂) 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 SO₂, 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 SO₂, 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 system to control mercury. Springerville Unit 3 has scrubbers to remove SO₂, 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 SO₂ removal and baghouses for particulate removal.

Basin and PNM, 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 NO_x emissions by lowering thermal NO_x formation.

Acid Rain Program. The acid rain program requires nationwide reductions of SO₂ and NO_x emissions by reducing allowable emission rates and by allocating emission allowances to generating facilities for SO₂ emissions based on historical or calculated levels, and reducing allowable NO_x 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 SO₂ 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 Environmental Protection Agency, or 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. Currently, our existing generating facilities generate approximately 63 percent of our energy resources, a substantial percentage of which is generated by coal-fired facilities. Emissions of carbon dioxide from our plants totaled approximately 13.0 million short tons in 2015. The Clean Power Plan establishes guidelines for states to develop plans to limit emissions of carbon dioxide from existing units. 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 that will be submitted to the EPA by September 2016. The EPA will take a year to review and approve state plans. States may request an extension up to September 2018. However, the United States 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. If 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. As of March 31, 2016, Nebraska, New Mexico, and Wyoming have stopped all work on the Clean Power Plan until litigation is completed. Arizona has stopped work on modeling and plan development, but is continuing meeting on a quarterly basis. Colorado has announced they are not developing a plan to submit to EPA but do plan to continue working on a carbon reduction plan, however, it is not clear at this time what they will actually be doing. The EPA also proposed a federal plan that would be implemented should states fail to submit acceptable plans. Comments on the proposed federal plan were submitted January 21, 2016.

The Clean Power Plan is the most complex and wide-ranging regulation under the Clean Air Act. We, along with 24 states, other utilities and national trade organizations, filed motions to stay the Clean Power Plan with the United States Court of Appeals for the District of Columbia Circuit, or 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. 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. On May 16, 2016, the D.C. Circuit Court of Appeals ordered, by its own motion, an *en banc* oral argument on September 27, 2016 for the challenges to the Clean Power Plan. The impacts of the final rule and any subsequent challenges cannot be determined at this time; however if the court upholds the final rule, it could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables) and transmission, investment in energy efficiency programs and decreased operation, or closure of coal-fired plants. On October 23, 2015, the EPA also issued a final New Source Performance Standard, or NSPS, for new and modified units that 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.

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 maximum achievable control technology, or 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 Mercury and Air Toxics Standard, or 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. On April 15, 2016, the Administrator signed EPA’s final supplemental notice in response to the Supreme Court’s remand of the MATS rule. 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 Springerville 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 New Source Review, or 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 best available retrofit technology, or BART, and states were to establish Reasonable Progress Goals in State Implementation Plans, or SIPs, to meet a 2064 goal of natural visibility conditions. The amended Regional Haze Rule could require additional controls for particulate matter, SO₂ and NO_x 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 SO₂ removal and the installation of low NO_x 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 SO₂ and NO_x emission limits for Craig Station Units 1, 2 and 3. Under the existing, approved SIP, we committed to NO_x 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 NO_x 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 NO_x controls.

Any source that emits SO₂, NO_x, 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 SO₂ provisions of the Regional Haze Rule by putting in place a backstop sulfur dioxide trading program. Arizona and New Mexico evaluated NO_x emission impacts on visibility and moved forward to develop Reasonable Progress rules for NO_x 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 NO_x 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 Federal Water Pollution Control Act, as amended, or 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 National Pollutant Discharge Elimination System, or 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 Resource Conservation and Recovery Act, as amended, or 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. Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or 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, Office of Surface Mining Reclamation and Enforcement, or 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 polychlorinated biphenyls, or 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

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

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

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.

Our system is interconnected with those of other utilities, including WAPA, Nebraska Public Power District, Black Hills Power, Inc., PacifiCorp, PSCO, Platte River Power Authority, Colorado Springs Utilities, Basin, TEP, PNM and Deseret Generation & Transmission Cooperative. The majority of our transmission facilities operate as part of the Western Interconnection, 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 Southwest Power Pool, or 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. A hearing at FERC is expected to begin in November 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 Public Utility Regulatory Policies Act of 1978, as amended, or 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. See “Legal Proceedings.” 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 Western Electricity Coordinating Council, or 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 Midwestern Reliability Organization, or 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 Multi-Regional Registered Entity, or MRRE, whereby WECC was designated our Lead Regional Entity. The intent of the MRRE program is to streamline compliance and enforcement efforts for entities registered in multiple regions.

In 2015, we were audited by WECC and are 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.

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. 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.

FERC Proceeding. On February 17, 2016, we filed a Petition for Declaratory Order with FERC seeking a declaratory order from FERC finding that the fixed cost recovery mechanism in our 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. On March 10, 2016, we filed a supplement to our petition providing that our Board adopted the revised Board policy on March 2, 2016. Motions to intervene or protests were due on or before March 25, 2016. Various individuals and entities filed comments and four entities filed motions to intervene, including our Member, DMEA. On April 8, 2016, we filed a Motion for Leave and Answer in response to motions to intervene and protests. On April 25, 2016, DMEA filed a Motion to Answer and Answer in response to our motion. Because of the early nature of the proceedings, we are unable to project the outcome of this matter although we do not believe it is likely to have a material adverse effect on our financial condition or our future results of operations or cash flows.

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, Jemez Mountains Electric Cooperative, Inc., or 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, Mora-San Miguel Electric Cooperative, Inc., or 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 "Tri-State Generation and Transmission Association, Inc.—Power Supply Resources—Water Supply."

Directors and Executive Officers

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 June 14, 2016 are as follows:

NAME	AGE	MEMBER-REPRESENTATIVE
Rick Gordon—Chairman and President	63	Mountain View Electric Association, Inc.
Joseph Wheeling—Vice Chairman	53	La Plata Electric Association, Inc..
Leo Brekel—Secretary	64	Highline Electric Association
Stuart Morgan—Treasurer	70	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	64	High Plains Power, Inc.
Julie Kilty—Assistant Secretary	57	Wyrulec Company
Hal Keeler—Executive Committee	87	Columbus Electric Cooperative, Inc.
William Mollenkopf—Executive Committee	66	Empire Electric Association, Inc.
Timothy Rabon—Executive Committee	56	Otero County Electric Cooperative, Inc.
Robert Bledsoe	67	K.C. Electric Association, Inc.
Jerry Burnett	69	High West Energy, Inc.
Tony Casados	70	Northern Rio Arriba Electric Association, Inc.
Richard Clifton	74	Carbon Power & Light, Inc.
Arthur W. Connell	63	Central New Mexico Electric Cooperative, Inc.
Lucas Cordova Jr.	51	Jemez Mountains Electric Cooperative, Inc.
John Finnerty	76	Wheatland Rural Electric Association, Inc.
Gary Fuchser	61	Northwest Rural Public Power District
John Gavan	60	Delta Montrose Electric Association
Jack Hammond	81	Niobrara Electric Association, Inc.
Ronald Hilkey	77	White River Electric Association, Inc.
Ralph Hilyard	77	Roosevelt Public Power District
Donald Kaufman	78	Sangre de Cristo Electric Association, Inc.
Donald Keairns	57	San Isabel Electric Association, Inc.
Thaine Michie	75	Poudre Valley Rural Electric Association, Inc.
Virginia Mondragon	51	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
Gary Rinker	64	Southwestern Electric Cooperative, Inc.
Arthur Rodarte	68	Kit Carson Electric Cooperative, Inc.
Claudio Romero	69	Continental Divide Electric Cooperative, Inc.
Donald Russell	69	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	66	Sierra Electric Cooperative, Inc.
Jerry Thompson	53	Garland Light & Power Company
Carl Trick II	68	Mountain Parks Electric, Inc.
Douglas Shawn Turner	55	The Midwest Electric Cooperative Corporation
Donald Wolberg	73	Socorro Electric Cooperative, Inc.
Scott Wolfe	52	San Luis Valley Rural Electric Cooperative, Inc.
William Wright	75	Southeast Colorado Power Association
Phillip Zochol	41	Panhandle Rural Electric Membership Association

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

Joseph Wheeling has served on our Board since May 2010 and is Vice Chairman of the Board. 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.

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.

Hal Keeler has served on our Board since July 2000. He is a member of the Executive Committee and 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 Western Fuels Association.

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

Timothy Rabon has served on our Board since April 2014. He is a member of the Executive Committee and 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.

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.

Tony Casados has served on our Board since July 2000. He is a member of 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 Western Fuels Association.

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 Elk Ridge 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 Elk Ridge.

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.

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

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.

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 Elk Ridge.

Darryl Sullivan has served on our Board since December 2013. He is a member of the Engineering and Operations Committee. Mr. Sullivan serves as a 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.

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

Scott Wolfe has served on our Board since June 2008. He is a member of the 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.

Executive Officers

The following table sets forth the names and positions of our executive officers and their ages as of June 14, 2016:

<u>NAME</u>	<u>AGE</u>	<u>POSITION</u>
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	53	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.

Compensation Discussion and Analysis

General Philosophy

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

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

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

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

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

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

Retirement Plans

Defined Benefit Plan. We participate in the National Rural Electric Cooperative Association, or 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, Elk Ridge, working at the New Horizon Mine. This plan is a qualified pension plan under the Internal Revenue Code of 1986, as amended, 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 ½ percent into each plan) for all non-bargaining employees. We offer one 401(k) plan (NRECA) to all employees of Elk Ridge working at the Colowyo Mine. We contribute 7 percent of employee salary and match up to an additional 5 percent of employee contributions. We offer one 401(k) plan (NRECA) to certain employees of Elk Ridge working at the New Horizon Mine and match 1 percent of bargaining employee contributions and contribute 1 percent of employee base salary for all non-bargaining employees. 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 Internal Revenue Service, or 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 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, Joseph Wheeling, Leo Brekel, Stuart Morgan, Matt M. Brown, Julie Kilty, Hal Keeler, William Mollenkopf, and Timothy Rabon serve as members of the Executive Committee.

Other than as noted below, no member of the Executive Committee is or previously was an officer or employee of us. Mr. Gordon is our Chairman and President, Mr. Wheeling 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 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 Chief Executive Officer	2015	\$680,711	\$ —	\$ —(2)	\$38,577	\$719,288
	2014	529,528	—	—(3)	34,406	563,934
	2013	386,576	7,350	443,113	35,942	872,981
Patrick Bridges Senior VP/CFO	2015	401,413	—	240,449	49,718	691,580
	2014	381,754	—	61,660	46,424	489,838
	2013	316,064	—	150,601	47,321	513,986
Ellen Connor Senior VP, Organizational Services/CTO	2015	265,138	—	400,891	27,960	693,989
	2014	203,078	—	—(3)	14,195	217,273
	2013	179,121	—	175,731	8,649	363,501
Barbara Walz Senior VP, Policy & Compliance/CCO	2015	316,163	—	288,468	37,977	642,608
	2014	269,036	—	—(3)	19,671	288,707
	2013	259,550	—	162,609	22,103	444,262
Bradford Nebergall Senior VP, Energy Management	2015	374,872	—	193,205	47,479	615,556
	2014	349,758	—	60,047	44,086	453,891
	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 had 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 ended on March 31, 2016. In consideration of the above mentioned employees continuing employment during such period, the

employee received a retention payment in April 2016 in the amount agreed to in the agreement as follows:

<u>Employee Title</u>	<u>Retention Payment</u>
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 was not an employment agreement and did 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.

<u>Name</u>	<u>Number of years Credited Service as of December 31, 2015</u>	<u>NRECA Retirement security Plan Present Value of Accumulated Benefit as of December 31, 2015</u>	<u>Pension Restoration Plan Present Value of Accumulated Benefit as of December 31, 2015</u>	<u>Payments During 2015</u>
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.

<u>Name</u>	<u>2015 Board Fees(1)</u>
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, Elk Ridge.

(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.

Security Ownership of Certain Beneficial Owners and Management

As a cooperative, we do not have any voting securities.

Related Party Transactions and Director Independence

Related Party 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 of Directors. 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 Elk Ridge, a subsidiary of ours, and/or the board of directors of other entities in which we have ownership interests, including Trapper Mining. We have multiple contracts with Elk Ridge for the purchase of coal for our facilities with a value of approximately \$84.2 million in 2015, which transactions were eliminated through financial consolidation. We purchased coal for the Yampa Project from Trapper Mining with a value of approximately \$17.7 million 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. We also 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.

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 and Executive Officers—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.

The Exchange Offer

This section of the prospectus describes the exchange offer. Although we believe that the description describes the material terms of the exchange offer, this summary may not contain all of the information that is important to you. You should carefully read this entire prospectus, for a complete understanding of the exchange offer.

Purpose and effects of the exchange offer

On May 23, 2016, or the issue date, we sold \$250.0 million aggregate principal amount of our 4.25% First Mortgage Bonds, Series 2016A, due 2046 in a private placement. On or after the issue date, the old bonds were resold to “qualified institutional buyers” as defined in and in compliance with Rule 144A under the Securities Act.

On May 23, 2016, we and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc., and Wells Fargo Securities, on behalf of itself and the other initial purchasers, entered into a registration rights agreement pursuant to which we agreed that we would file a registration statement with the SEC relating to an offer to exchange the old bonds for SEC-registered bonds with terms identical to the old bonds (except that the transfer restrictions, registration rights and additional interest provisions relating to the old bonds would not apply to the new bonds). The exchange offer will remain open for at least 20 business days after the date we mail notice of the exchange offer to bondholders. We will use our commercially reasonable efforts to have the registration statement be declared effective under the Securities Act with 150 days after the issue date of the old bonds and to use our commercially reasonable efforts to commence the exchange offer promptly after the declaration of effectiveness. If the registration statement is not declared effective by the SEC within 150 days of the issuance of the old bonds or the exchange offer is not completed within 30 business days after the commencement of the exchange offer, the annual interest rate borne by the old bonds will be increased.

The term “holder” with respect to the exchange offer means any person in whose name old bonds are registered on our books or the books of The Depository Trust Company, or DTC, or any other person who has obtained a properly completed certificate of transfer from the registered holder, or any person whose old bonds are held of record by DTC who desires to deliver such old bonds by book-entry transfer at DTC.

We have not requested, and do not intend to request, an interpretation by the staff of the SEC with respect to whether the new bonds issued in the exchange offer in exchange for the old bonds may be offered for resale, resold or otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act. Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe the new bonds issued in exchange for old bonds may be offered for resale, resold and otherwise transferred by any holder without compliance with the registration and prospectus delivery provisions of the Securities Act provided that:

- you are not a broker-dealer that purchased old bonds directly from us for resale pursuant to Rule 144A under the Securities Act or any other available exemption under the Securities Act;
- you are not our “affiliate”; and
- you acquire the new bonds in the ordinary course of your business and that you have no arrangement or understanding with any person to participate in the distribution of the new bonds.

Any holder that tenders in the exchange offer with the intention to participate, or for the purpose of participating, in a distribution of the new bonds or that is our affiliate may not rely upon such

interpretations by the staff of the SEC and, in the absence of an exemption, must comply with the registration and prospectus delivery provisions of the Securities Act in connection with any secondary resale transaction. Any holder that fails to comply with such requirements may incur liabilities under the Securities Act for which the holder will not be indemnified by us. Each broker-dealer (other than an affiliate of ours) that receives new bonds for its own account in the exchange offer must acknowledge that it will deliver a prospectus meeting the requirements of the Securities Act in connection with any resale of new bonds. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. We have agreed that, for a period of 90 days following the completion of the exchange offer, we will make this prospectus available to any broker-dealer for use in connection with any such resale. See “Plan of Distribution.”

We are not making the exchange offer to, nor will we accept surrenders for exchange from, holders of old bonds in any jurisdiction in which the exchange offer or its acceptance would not comply with applicable securities or blue sky laws.

By tendering in the exchange offer, you will represent to us that, among other things:

- you are acquiring the new bonds in the exchange offer in the ordinary course of your business, whether or not you are a holder;
- you are transferring good and marketable title to the old bonds free and clear of all liens, security interests, charges or encumbrances or rights of parties other than you;
- you do not have an arrangement or understanding with any person to participate in the distribution of the new bonds;
- you are not a broker-dealer, or if you are a broker-dealer, you will comply with the registration and prospectus delivery provisions of the Securities Act to the extent applicable;
- you are not our “affiliate” within the meaning of Rule 405 under the Securities Act or, if you are our “affiliate,” you will comply with the registration and prospectus delivery provisions of the Securities Act to the extent applicable; and
- you are not engaged in and do not intend to engage in the distribution of the new bonds.

Following the completion of the exchange offer, the holders of old bonds will not have any further registration rights (except in the limited circumstances provided under the registration rights agreement), and the old bonds will continue to be subject to certain restrictions on transfer. See “—Consequences of failure to exchange.” Accordingly, the liquidity of the market for the old bonds could be adversely affected.

Participation in the exchange offer is voluntary and you should carefully consider whether to accept. We urge you to consult your financial and tax advisors in making your own decision on whether to participate in the exchange offer.

Consequences of failure to exchange

The old bonds that are not exchanged for new bonds in the exchange offer will remain restricted securities within the meaning of Rule 144(a)(3) of the Securities Act and subject to restrictions on transfer. Accordingly, such old bonds may not be offered, sold, pledged or otherwise transferred except:

- (1) to us or any of our subsidiaries, upon redemption thereof or otherwise;
- (2) so long as the old bonds are eligible for resale pursuant to Rule 144A under the Securities Act, to a person whom the seller reasonably believes is a qualified institutional buyer within the meaning of Rule 144A under the Securities Act, purchasing for its own account or for the

account of another qualified institutional buyer to whom notice is given that the resale, pledge or other transfer is being made in reliance on Rule 144A under the Securities Act;

- (3) in an offshore transaction in accordance with Regulation S under the Securities Act;
- (4) to an institutional “accredited investor” (within the meaning of Rule 501(a)(1), (2), (3) or (7) under the Securities Act) that is not a qualified institutional buyer and that is purchasing old bonds for its own account or for the account of another institutional accredited investor, in each case in a minimum principal amount of old bonds of \$250,000;
- (5) in reliance on another exemption from the registration requirements of the Securities Act; or
- (6) pursuant to an effective registration statement under the Securities Act.

In all of the situations discussed above, the resale must be in accordance with the Securities Act and any other applicable securities laws. In the case of (3), (4) and (5) above, we or the trustee under the Master Indenture may require the delivery of an opinion of counsel, a certification or other information satisfactory to us or such trustee.

To the extent old bonds are tendered and accepted in the exchange offer, the principal amount of outstanding old bonds will decrease. Accordingly, the liquidity of the market for the old bonds could be adversely affected.

Terms of the exchange offer

Upon the terms and subject to the conditions set forth in this prospectus and in the letter of transmittal, we will accept any and all old bonds validly tendered and not validly withdrawn on or prior to the expiration date of the exchange offer. We will issue new bonds in exchange for the same principal amount of old bonds accepted in the exchange offer. The new bonds will accrue interest on the same terms as the old bonds; however, holders of the old bonds accepted for exchange will not receive accrued interest thereon at the time of exchange; rather, all accrued interest on the old bonds will become obligations under the new bonds. Holders may tender some or all of their old bonds pursuant to the exchange offer. However, old bonds may be tendered only in principal amounts equal to \$2,000 and integral multiples of \$1,000 in excess thereof.

The form and terms of the new bonds are the same as the form and terms of the old bonds, except that the new bonds will have been registered under the Securities Act and will not bear legends restricting their transfer pursuant to the Securities Act, and, except in the limited circumstances provided under the registration rights agreement, holders of the new bonds will not be entitled to the rights of holders of old bonds under the registration rights agreement.

The new bonds will evidence the same debt as the old bonds that they replace, and will be issued under, and be entitled to the benefits of, the Master Indenture which governs all of the bonds, including the payment of principal and interest.

We are sending this prospectus and the letter of transmittal to all registered holders of outstanding old bonds. Only a registered holder of old bonds or such holder’s legal representative or attorney-in-fact as reflected on the records of the trustee under the Master Indenture may participate in the exchange offer. There will be no fixed record date for determining the holders of old bonds entitled to participate in the exchange offer.

Holders of the old bonds do not have any appraisal or dissenter’s rights under Colorado law or the Master Indenture that governs the bonds in connection with the exchange offer. We intend to conduct the exchange offer in accordance with the requirements of the Exchange Act and the SEC’s rules and regulations thereunder.

We will be deemed to have accepted validly tendered old bonds when, as and if we have given oral or written notice thereof to the exchange agent. The exchange agent will act as agent for the tendering holders of the old bonds for the purposes of receiving the new bonds. The new bonds delivered in the exchange offer will be issued promptly following the expiration date of the exchange offer, unless the exchange offer is withdrawn.

If any tendered old bonds are not accepted for exchange because of an invalid tender, our withdrawal of the exchange offer, the occurrence of certain other events set forth herein or otherwise, certificates for any such unaccepted old bonds will be returned, without expense, to the tendering holder, unless otherwise provided in the letter of transmittal, promptly after the expiration date of the exchange offer or our withdrawal of the exchange offer, as applicable. Any acceptance, waiver of default or rejection of a tender of bonds shall be at our sole discretion and shall be conclusive, final and binding.

Holders that tender old bonds in the exchange offer will not be required to pay brokerage commissions or fees or, subject to the instructions in the letter of transmittal, transfer taxes with respect to the exchange of old bonds in the exchange offer. We will pay all charges and expenses, other than certain taxes, in connection with the exchange offer. See “—Fees and expenses.”

Expiration date; extensions; amendments

The term expiration date with respect to the exchange offer means 5:00 p.m., New York City time, on _____, 2016 unless we, in our sole discretion, extend the exchange offer, in which case the term expiration date shall mean the latest date and time to which the exchange offer is extended.

If we extend the exchange offer, we will notify the exchange agent of any extension by oral or written notice and will make a public announcement thereof, each prior to 9:00 a.m., New York City time, on the next business day after the previously scheduled expiration date. Any extension notice will disclose the approximate number of old bonds deposited or tendered by holders as of the date of the notice to extend the exchange offer.

We reserve the right, in our sole discretion, to extend the exchange offer; if any of the conditions set forth below under “—Conditions to the exchange offer” have not been satisfied, to terminate the exchange offer; or to amend the terms of the exchange offer in any manner. We may effect any such extension, termination or amendment by giving oral or written notice thereof to the exchange agent.

Except as specified in the second paragraph under this heading, we will make a public announcement of any such extension, termination or amendment as promptly as practicable. If we amend the exchange offer in a manner determined by us to constitute a material change, we will promptly disclose such amendment in a prospectus supplement that will be distributed to the registered holders of the old bonds. The exchange offer will then be extended for a period of five to ten business days, as required by law, depending upon the significance of the amendment and the manner of disclosure to the registered holders.

We will make a timely release of a public announcement of any extension, termination or amendment to the exchange offer to an appropriate news agency.

Procedures for tendering old bonds

Tenders of old bonds. The tender by a holder of old bonds pursuant to any of the procedures set forth below will constitute the tendering holder’s acceptance of the terms and conditions of the exchange offer. Our acceptance for exchange of old bonds tendered pursuant to any of the procedures described below will constitute a binding agreement between such tendering holder and us in accordance with the terms and subject to the conditions of the exchange offer. Only holders are

authorized to tender their old bonds. The procedures by which old bonds may be tendered by beneficial owners that are not holders will depend upon the manner in which the old bonds are held.

DTC has authorized DTC participants that are beneficial owners of old bonds through DTC to tender their old bonds as if they were holders. To effect a tender, DTC participants should either (1) complete and sign the letter of transmittal or a facsimile thereof, have the signature thereon guaranteed if required by Instruction 1 of the letter of transmittal and deliver the letter of transmittal or such facsimile pursuant to the procedures for book-entry transfer set forth below under “—Book-entry delivery procedures” or (2) transmit their acceptance to DTC through the DTC Automated Tender Offer Program, or ATOP, for which the exchange offer will be eligible, and follow the procedures for book-entry transfer set forth below under “—Book-entry delivery procedures.”

Tender of old bonds held in physical form. To tender old bonds held in physical form in the exchange offer:

- the exchange agent must receive, at the address set forth in this prospectus, a properly completed letter of transmittal applicable to such old bonds (or a facsimile thereof) duly executed by the tendering holder and any other documents the letter of transmittal requires, and tendered old bonds must be received by the exchange agent at such address (or delivery effected through the deposit of old bonds into the exchange agent’s account with DTC and making book-entry delivery as set forth below) on or prior to the expiration date of the exchange offer; or
- the tendering holder must comply with the guaranteed delivery procedures set forth below on or prior to the expiration date of the exchange offer.

Letters of transmittal and old bonds should be sent only to the exchange agent and should not be sent to us.

Tender of old bonds held through a custodian. To tender old bonds that a custodian bank, depository, broker, trust company or other nominee holds of record, the beneficial owner thereof must instruct such holder to tender the old bonds on the beneficial owner’s behalf. A letter of instructions from the record owner to the beneficial owner may be included in the materials provided along with this prospectus, which the beneficial owner may use to instruct the registered holder of such beneficial owner’s old bonds to effect the tender.

Tender of old bonds held through DTC. To tender old bonds that are held through DTC, DTC participants on or prior to the expiration date of the exchange offer should either:

- properly complete and duly execute the letter of transmittal (or a facsimile thereof) and any other documents required by the letter of transmittal, and deliver the letter of transmittal or such facsimile pursuant to the procedures for book-entry transfer set forth below; or
- transmit their acceptance through ATOP, for which the exchange offer will be eligible, and DTC will then edit and verify the acceptance and send an Agent’s Message to the exchange agent for its acceptance.

The term Agent’s Message means a message transmitted by DTC to, and received by, the exchange agent, and forming a part of the Book-Entry Confirmation (as defined below), which states that DTC has received an express acknowledgment from a participant in DTC tendering the old bonds and that such participant has received the letter of transmittal, agrees to be bound by the terms of the letter of transmittal and we may enforce such agreement against such participant.

Tendered old bonds held through DTC must be delivered to the exchange agent pursuant to the book-entry delivery procedures set forth below or the tendering DTC participant must comply with the guaranteed delivery procedures set forth below.

The method of delivery of old bonds and letters of transmittal, any required signature guarantees and all other required documents, including delivery through DTC and any acceptance or Agent's Message transmitted through ATOP, is at the election and risk of the person tendering old bonds and delivering letters of transmittal. If you use ATOP to tender, you must allow sufficient time for completion of the ATOP procedures during normal business hours of DTC on or prior to the expiration date of the exchange offer. Except as otherwise provided in the letter of transmittal, tender and delivery will be deemed made only when actually received by the exchange agent. If delivery is by mail, it is suggested that the holder use properly insured, registered mail with return receipt requested, and that the mailing be made sufficiently in advance of the expiration date of the exchange offer to permit delivery to the exchange agent on or prior to such date.

Except as provided below, unless the old bonds being tendered are deposited with the exchange agent on or prior to the expiration date of the exchange offer (accompanied by a properly completed and duly executed letter of transmittal or a properly transmitted Agent's Message), we may, at our option, reject such tender. Exchange of new bonds for old bonds will be made only against deposit of the tendered old bonds and delivery of all other required documents.

Book-entry delivery procedures. The exchange agent will establish accounts with respect to the old bonds at DTC for purposes of the exchange offer within two business days after the date of this prospectus, and any financial institution that is a participant in DTC may make book-entry delivery of the old bonds by causing DTC to transfer such old bonds into the exchange agent's account in accordance with DTC's procedures for such transfer. However, although delivery of old bonds may be effected through book-entry at DTC, the letter of transmittal (or facsimile thereof), with any required signature guarantees or an Agent's Message in connection with a book-entry transfer, and any other required documents, must, in any case, be transmitted to and received by the exchange agent at its address set forth in this prospectus on or prior to the expiration date of the exchange offer, or compliance must be made with the guaranteed delivery procedures described below. Delivery of documents to DTC does not constitute delivery to the exchange agent. The confirmation of a book-entry transfer into the exchange agent's account at DTC as described above is referred to as a Book-Entry Confirmation.

Signature guarantees. Signatures on all letters of transmittal must be guaranteed by a recognized member of the Medallion Signature Guarantee Program or by any other "eligible guarantor institution," as that term is defined in Rule 17Ad-15 under the Exchange Act, either of which we refer to as an Eligible Institution, unless the old bonds tendered thereby are tendered (1) by a registered holder of old bonds (or by a participant in DTC whose name appears on a DTC security position listing as the owner of such old bonds) that has not completed either the box entitled "Special Issuance Instructions" or "Special Delivery Instructions" on the letter of transmittal or (2) for the account of an Eligible Institution. See Instruction 1 of the letter of transmittal. In addition, if the old bonds are registered in the name of a person other than the signer of the letter of transmittal or if old bonds not accepted for exchange or not tendered for exchange are to be returned to a person other than the registered holder, then the signature on the letter of transmittal accompanying the tendered old bonds must be guaranteed by an Eligible Institution as described above. See Instructions 1 and 5 of the letter of transmittal.

Guaranteed delivery. If you wish to tender your old bonds but they are not immediately available or if you cannot deliver your old bonds, the letter of transmittal and any other required documents to the exchange agent or comply with the applicable procedures under ATOP on or prior to the expiration date of the exchange offer, you may tender if:

- the tender is made by or through an Eligible Institution;

- on or prior to the expiration date of the exchange offer, the exchange agent receives from that Eligible Institution either a properly completed and duly executed notice of guaranteed delivery by facsimile transmission, mail, courier or overnight delivery or a properly transmitted Agent's Message relating to a notice of guaranteed delivery;
- stating your name and address, the certificate number or numbers of your old bonds and the principal amount of old bonds tendered;
- stating that the tender is being made thereby; and
- guaranteeing that, within three business days after the expiration date of the exchange offer, the letter of transmittal or a facsimile thereof or an Agent's Message in lieu thereof, together with the old bonds or a Book-Entry Confirmation, and any other documents required by the letter of transmittal, will be deposited by the Eligible Institution with the exchange agent; and
- the exchange agent receives such properly completed and executed letter of transmittal or facsimile or Agent's Message, as well as all tendered old bonds in proper form for transfer or a Book-Entry Confirmation, and all other documents required by the letter of transmittal, within three business days after the expiration date of the exchange offer.

Upon request to the exchange agent, the exchange agent will send a notice of guaranteed delivery to you if you wish to tender your old bonds according to the guaranteed delivery procedures described above.

Determination of validity. All questions as to the validity, form, eligibility (including time of receipt), acceptance and withdrawal of tendered old bonds will be determined by us in our sole discretion, which determination will be conclusive, final and binding. Alternative, conditional or contingent tenders of old bonds will not be considered valid and may not be accepted. We reserve the absolute right to reject any and all old bonds not properly tendered or any old bonds our acceptance of which, in the opinion of our counsel, would be unlawful.

We also reserve the right to waive any defects, irregularities or conditions of tender as to particular old bonds. The interpretation of the terms and conditions of the exchange offer (including the instructions in the letter of transmittal) by us will be conclusive, final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of old bonds must be cured within such time as we shall determine.

Although we intend to notify holders of defects or irregularities with respect to tenders of old bonds through the exchange agent, neither we, the exchange agent nor any other person is under any duty to give such notification, nor shall we or they incur any liability for failure to give such notification. Tenders of old bonds will not be deemed to have been made until such defects or irregularities have been cured or waived.

Any old bonds received by the exchange agent that are not validly tendered and as to which the defects or irregularities have not been cured or waived, or if old bonds are submitted in a principal amount greater than the principal amount of old bonds being tendered by a tendering holder, such unaccepted or non-exchanged old bonds will either be:

- returned by the exchange agent to the tendering holder; or
- in the case of old bonds tendered by book-entry transfer into the exchange agent's account at DTC pursuant to the book-entry delivery procedures described above, credited to an account maintained with DTC.

Withdrawal of tenders

Except as otherwise provided herein, tenders of old bonds in the exchange offer may be withdrawn at any time on or prior to the expiration date of the exchange offer. To be effective, a written or facsimile transmission notice of withdrawal must be received by the exchange agent at its address set forth in this prospectus on or prior to the expiration date of the exchange offer. Any such notice of withdrawal must:

- specify the name of the person having deposited the old bonds to be withdrawn;
- identify the old bonds to be withdrawn, including the certificate number or numbers of the particular certificate or certificates evidencing the old bonds (unless such old bonds were tendered by book-entry transfer), and aggregate principal amount of such old bonds; and
- be signed by the holder in the same manner as the original signature on the letter of transmittal (including any required signature guarantees) or be accompanied by documents of transfer sufficient to have the trustee under the Master Indenture register the transfer of the old bonds into the name of the person withdrawing such old bonds.

If old bonds have been delivered pursuant to the procedures for book-entry transfer set forth in “—Procedures for tendering old bonds—Book-entry delivery procedures,” any notice of withdrawal must specify the name and number of the account at DTC to be credited with such withdrawn old bonds and must otherwise comply with DTC procedures.

If the old bonds to be withdrawn have been delivered or otherwise identified to the exchange agent, a signed notice of withdrawal meeting the requirements discussed above is effective immediately upon written or facsimile notice of withdrawal even if physical release is not yet effected. A withdrawal of tendered old bonds can only be accomplished in accordance with these procedures.

All questions as to the validity, form and eligibility (including time of receipt) of notices of withdrawal will be determined by us in our sole discretion, which determination shall be conclusive, final and binding on all parties. No withdrawal of tendered old bonds will be deemed to have been properly made until all defects or irregularities have been cured or expressly waived. Neither we, the exchange agent nor any other person will be under any duty to give notification of any defects or irregularities in any notice of withdrawal, nor shall we or they incur any liability for failure to give any such notification. Any old bonds so withdrawn will be deemed not to have been validly tendered for purposes of the exchange offer and no new bonds will be issued with respect thereto unless the old bonds so withdrawn are retendered on or prior to the expiration date of the exchange offer. Properly withdrawn old bonds may be retendered by following one of the procedures described above under “—Procedures for tendering old bonds” at any time on or prior to the expiration date of the exchange offer.

Any old bonds which have been tendered but which are not accepted for exchange due to the rejection of the tender due to uncured defects or the prior termination of the exchange offer, or which have been validly withdrawn, will be returned to the holder thereof, unless otherwise provided in the letter of transmittal, promptly following the expiration date of the exchange offer or the termination of the exchange offer, as applicable, or, if so requested in a notice of withdrawal, promptly after receipt by us of the notice of withdrawal, without cost to such holder.

Conditions to the exchange offer

The exchange offer is not subject to any conditions, other than that:

- the exchange offer, or the making of any exchange by a holder, does not violate applicable law or any applicable interpretation of the staff of the SEC;

- there shall not have been instituted, threatened or be pending any action or proceeding before or by any court, governmental, regulatory or administrative agency or instrumentality, or by any other person, in connection with the exchange offer, that would or might, in our reasonable judgment, prohibit, prevent, restrict or delay completion of the exchange offer;
- no order, statute, rule, regulation, executive order, stay, decree, judgment or injunction shall have been proposed, enacted, entered, issued, promulgated, enforced or deemed applicable by any court or governmental, regulatory or administrative agency or instrumentality that, in our reasonable judgment, would or might prohibit, prevent, restrict or delay completion of the exchange offer, or that is, or is reasonably likely to be, materially adverse to the business, operations, properties, condition (financial or otherwise), assets, liabilities or prospects of us, our subsidiaries or our affiliates;
- there shall not have occurred or be likely to occur any event affecting the business, operations, properties, condition (financial or otherwise), assets, liabilities or prospects of us, our subsidiaries or our affiliates that, in our reasonable judgment, would or might prohibit, prevent, restrict or delay completion of the exchange offer;
- the trustee under Master Indenture shall not have objected in any respect to or taken any action that could, in our sole reasonable judgment, adversely affect the completion of the exchange offer, or shall have taken any action that challenges the validity or effectiveness of the procedures used by us in soliciting or the making of the exchange offer; and
- there shall not have occurred (a) any general suspension of, or limitation on prices for, trading in the United States securities or financial markets, (b) a material impairment in the trading market for debt securities, (c) a declaration of a banking moratorium or any suspension of payments in respect of banks in the United States, (d) any limitation (whether or not mandatory) by any government or governmental, administrative or regulatory authority or agency, domestic or foreign, or other event that, in our reasonable judgment, might affect the extension of credit by banks or other lending institutions, (e) an outbreak or escalation of hostilities or acts of terrorism involving the United States or a declaration of a national emergency or war by the United States or any other calamity or crisis or any other change in political, financial or economic conditions, if the effect of any such event, in our reasonable judgment, makes it impractical or inadvisable to proceed with the exchange offer or (f) in the case of any of the foregoing existing on the date hereof, a material acceleration or worsening thereof.

If we determine in our reasonable discretion that any of the conditions to the exchange offer are not satisfied, we may:

- refuse to accept any old bonds and return all tendered old bonds to the tendering holders;
- terminate the exchange offer;
- extend the exchange offer and retain all tendered old bonds, subject, however, to the rights of holders to withdraw such tendered old bonds; or
- waive such unsatisfied conditions with respect to the exchange offer and accept all validly tendered old bonds that have not been validly withdrawn. If such waiver constitutes a material change to the exchange offer, we will promptly disclose such waiver by means of a prospectus supplement that will be distributed to the registered holders of the old bonds, and will extend the exchange offer for a period of five to ten business days, depending upon the significance of the waiver and the manner of disclosure to the registered holders, if the exchange offer would otherwise expire during such five to ten business day period.

Exchange agent

Wells Fargo Bank, National Association, the trustee under Master Indenture, has been appointed as exchange agent for the exchange offer. You should direct questions and requests for assistance, requests for additional copies of this prospectus or of the letter of transmittal and requests for notices of guaranteed delivery and other documents to the exchange agent addressed as follows:

By Registered or Certified Mail:	By Regular Mail or Courier:	In Person by Hand Only:
Wells Fargo Bank, N.A.	Wells Fargo Bank, N.A.	Wells Fargo Bank, N.A.
Corporate Trust Operations	Corporate Trust Operations	Corporate Trust Operations
MAC N9303-121	MAC N9303-121	Northstar East Building—12 th Floor
P.O. Box 1517	6 th St & Marquette Avenue	608 Second Avenue South
Minneapolis, MN 55480	Minneapolis, MN 55479	Minneapolis, MN 55402

By Facsimile Transmission (Eligible Institutions Only): (877) 407-4679

To Confirm by Telephone, or for Information: (800) 344-5128

Fees and expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail by the exchange agent; however, additional solicitations may be made by telegraph, teletype, telephone or in person by our or our affiliates' officers and regular employees.

No dealer manager has been retained in connection with the exchange offer and no payments will be made to brokers, dealers or others soliciting acceptance of the exchange offer. However, reasonable and customary fees will be paid to the exchange agent for its services and it will be reimbursed for its reasonable out-of-pocket expenses.

Our out-of-pocket expenses for the exchange offer will include fees and expenses of the exchange agent and the trustee under the Master Indenture, accounting and legal fees and printing costs, among others.

Transfer taxes

We will pay all transfer taxes, if any, applicable to the exchange of the old bonds pursuant to the exchange offer. If, however, a transfer tax is imposed for any reason other than the exchange of the old bonds pursuant to the exchange offer, then the amount of any such transfer tax (whether imposed on the registered holder or any other person) will be payable by the tendering holder. If satisfactory evidence of payment of such tax or exemption therefrom is not submitted with the letter of transmittal, the amount of such transfer tax will be billed directly to such tendering holder.

Description of the Bonds

General

We have issued the old bonds and will issue the new bonds described in this prospectus under the indenture, dated effective as of December 15, 1999 (the “Master Indenture”), between us and Wells Fargo Bank, National Association, as trustee (the “Master Trustee”). The terms of the new bonds include those expressly set forth in the Master Indenture and those made part of the Master Indenture by reference to the Trust Indenture Act of 1939, as amended (the “Trust Indenture Act”).

The following summary of the bonds is not complete and is subject in all respects to the provisions of, and is qualified in its entirety by reference to, the Master Indenture and the bonds. We urge you to read the Master Indenture and the bonds because it, not this description, defines the rights of holders of the bonds. Capitalized terms used in this “Description of the Bonds” section which are not otherwise defined shall have the meanings set forth in the Master Indenture. As used in this “Description of the Bonds” section, except as the context otherwise requires, the term “bonds” means all 4.25% First Mortgage Bonds, Series 2016A, due 2046, issued pursuant to the Master Indenture in exchange for the old bonds. Wherever particular provisions of the Master Indenture or terms defined therein are referred to, those provisions or definitions are incorporated by reference as a part of the statements made in this prospectus and these statements are qualified in their entirety by such reference. References to “Articles” and “Sections,” unless otherwise indicated, are references to article and section numbers of the Master Indenture.

The bonds will be represented by one or more global bonds issued in fully registered form that, when issued, will be registered in the name of Cede & Co., as registered owner and as nominee for DTC. References in this summary and in the Master Indenture to the “holders” or “bondholders” with respect to global bonds issued in fully registered form refer to Cede & Co. as registered owner and nominee for DTC. DTC will act as securities depository for such bonds, with certain exceptions. Purchases of beneficial interests in the bonds will be made in book-entry form.

Interest

The bonds will bear interest at the rate of 4.25% per annum. Interest on the bonds will accrue from May 23, 2016, payable in arrears semi-annually on each June 1 and December 1 (each an “Interest Payment Date”) to the persons in whose names they are registered at the close of business on the preceding May 15 and November 15, respectively (each a “Regular Record Date”); provided, however, that interest payable at maturity (whether at stated maturity, upon redemption or otherwise, hereinafter “Maturity”) will be payable to the registered bondholder to whom principal is payable. The first Interest Payment Date will be December 1, 2016.

Interest on each bond will be payable on each Interest Payment Date for each bond for the period commencing on the next preceding Interest Payment Date (or if no interest has been paid thereon, commencing on the date of issuance thereof) to, but not including, the Interest Payment Date.

If any Interest Payment Date or the date of Maturity falls on a day that is not a Business Day (as defined below), all payments to be made on such day shall be made on the next succeeding Business Day with the same force and effect as if made on the due date, and no additional interest shall be payable as a result of such delay in payment. Interest will be computed on the basis of a 360-day year of twelve 30-day months.

Any interest payable on any Interest Payment Date other than Maturity and not so punctually paid or duly provided for will cease to be payable to the person in whose name the bond is registered at the close of business on the applicable Regular Record Date and will instead be payable to the person in whose name the bond (or one or more predecessor bonds) is registered at the close of business on a special record date for the payment of such interest, notice of which shall be given to the registered

holders of the bonds (or one or more predecessor bonds) not less than 10 days prior to the special record date. The Master Trustee shall fix a special record date which shall not be more than 15 days nor less than 10 days prior to the date we propose for payment of such defaulted interest, and not less than 10 days after the receipt by the Master Trustee of the notice of the proposed payment.

“*Business Day*” shall mean any day except a Saturday, Sunday, holiday or day on which banking institutions in the cities of Denver, Colorado or Washington, D.C. or the city in which the principal corporate trust office of the Master Trustee is located are closed.

Payment of Bonds at Maturity; Transfers; Exchanges

The principal of and premium, if any, and interest on the bonds at Maturity will be payable upon presentation of the bonds at the corporate trust office of Wells Fargo Bank, National Association in Minneapolis, Minnesota, as paying agent. We may change the place of payment, may appoint one or more additional paying agents (including us) and may remove any paying agent, all at its discretion.

The transfer of bonds may be registered, and bonds may be exchanged for other bonds of the same series, of authorized denominations and of like tenor and aggregate principal amount, at the office or agency of the Master Trustee as the Paying Agent, as security registrar for the bonds. We may change the place for registration of transfer and exchange of the bonds, and may designate one or more additional places for such registration and exchange, all at its discretion. No service charge will be made for any transfer or exchange of the bonds; however, we may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any registration of transfer or exchange of the bonds. We will not be required to execute or to provide for the registration of transfer of or the exchange of (a) any bond during a period of 15 days prior to giving any notice of redemption or (b) any bond selected for redemption in whole or in part, except the unredeemed portion of any bond being redeemed in part.

Subject to the applicable laws regarding abandoned property, all moneys we pay to a paying agent or the Master Trustee (or then held by us, in trust) for the payment of the principal of or any premium or interest on a bond which remain unclaimed at the end of two years after such principal, premium or interest has become due and payable will be (provided no Event of Default has occurred and is continuing) repaid to us at our request (or if then held by us shall be discharged from such trust), and the holder of such bond thereafter may, as an unsecured general creditor, look only to us for payment thereof, and all liability of the paying agent, the Master Trustee and us as trustee with respect thereto shall thereupon cease.

Redemption

At any time before December 1, 2045 (which is the date that is six months prior to the maturity date of the bonds) or from time to time, we may, at our option, redeem the bonds, in whole or in part at a “make whole” redemption price equal to the greater of:

100% of the principal amount of the bonds being redeemed; and

the sum of the present values of the remaining scheduled principal and interest payments on the bonds being redeemed (not including any portion of such payments of interest accrued as of the redemption date), discounted to the redemption date on a semi-annual basis (on the basis of a 360-day year of twelve 30-day months) at a rate equal to the sum of (i) the yield to maturity, determined on the third Business Day prior to the redemption date, of the U.S. Treasury security having a life equal to the remaining average life of the maturity of bonds being redeemed and trading in the secondary market at the price closest to par, and (ii) 25 basis points with respect to the bonds;

plus, in either case, accrued and unpaid interest thereon to but excluding the redemption date.

At any time on or after December 1, 2045 (which is the date that is six months prior to the maturity date of the bonds), the bonds will be redeemable upon not less than 30 nor more than 60 days' prior notice given to the holders of the bonds to be redeemed, at a redemption price equal to 100 percent of the principal amount of the bonds to be redeemed plus in each case accrued and unpaid interest to, but excluding, the date of redemption.

If there is no U.S. Treasury security having a life equal to the remaining average life of the bonds being redeemed, the discount rate will be calculated using a yield to maturity determined on a straight-line basis (rounding to the nearest calendar month, if necessary) from the average yield to maturity, determined on the third Business Day prior to the redemption date, of two U.S. Treasury securities having lives most closely corresponding to the remaining average life of the bonds being redeemed and trading in the secondary market at the price closest to par.

We must give at least 30 days', but not more than 60 days', prior notice of redemption mailed to the registered address of each holder of bonds being redeemed except as otherwise required by the procedures of DTC. If less than all of the outstanding bonds are to be redeemed, the bonds to be redeemed will be selected by the Master Trustee in any method it deems fair and appropriate, and the portion of the bonds not so redeemed will be in a minimum denomination of \$2,000 and integral multiples of \$1,000 in excess thereof.

If at the time of mailing of notice for the optional redemption we have not deposited with the Master Trustee moneys sufficient to redeem all of the bonds called for redemption, the notice of optional redemption given by the Master Trustee will so state and will further state that the redemption of the bonds is conditional upon our providing, or causing to be provided, to the Master Trustee, by 2:00 p.m. New York City time, on the redemption date, funds sufficient to effect the redemption, and the bonds will not be redeemed unless such funds are deposited. The failure of the Master Trustee to have sufficient funds to effect the redemption will not constitute a payment or other default by us under the Master Indenture and we will not be liable to any holder of those bonds as a result of the failed redemption. If the Master Trustee has enough designated funds on deposit to effect a redemption at the time we give notice of the redemption, then we are obligated to redeem the bonds as provided in that notice.

The bonds do not provide for any sinking fund.

Book-Entry Securities

The bonds will be evidenced by one or more global bonds, in fully registered form, without coupons, or the Global Bonds. We will deposit the Global Bonds with a custodian for and registered in the name of Cede & Co. as nominee of DTC as depository for the Global Bonds. Beneficial interests in the Global Bonds will be shown on, and transfers of beneficial interests will be effected only through, records maintained by DTC and its participants. Beneficial interests in the Global Bonds will be exchanged for bonds in certificated form only under the limited circumstances described below.

A beneficial interest in a Global Bond that is transferred to a person who takes delivery through another Global Bond will, upon transfer, become subject to any transfer restrictions and other procedures applicable to beneficial interests in the other Global Bond.

The information in this section concerning DTC and its respective procedures has been obtained from sources that we believe to be reliable, but we do not take responsibility for its accuracy.

DTC

DTC is a limited-purpose trust company organized under the laws of the State of New York, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial

Code and a “clearing agency” registered pursuant to the provisions of Section 17A of the Exchange Act. DTC was created to hold securities for its participating organizations (collectively, the “Participants”) and to facilitate the clearance and settlement of transactions in those securities between the Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers (including the initial purchasers), banks, trust companies, clearing corporations and certain other organizations. Access to DTC’s system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the “Indirect Participants”). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through the Participants or the Indirect Participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and Indirect Participants.

Upon the issuance of the bonds in registered form, DTC will credit, on its book-entry registration and transfer system, the respective principal amounts of the bonds represented by the Global Bonds, including those held through Euroclear or Clearstream, to the accounts of Participants. The accounts to be credited shall be designated by the initial purchaser. Ownership of beneficial interests in the Global Bonds will be limited to Participants or persons that may hold interests through Participants. Ownership of beneficial interests by Participants in the Global Bonds will be shown on, and the transfer of that ownership interest will be effected only through, records maintained by DTC or its nominee. Ownership of beneficial interests in the Global Bonds by persons that hold through Participants will be shown on, and the transfer of that ownership interest within such Participant will be effected only through, records maintained by such Participant. Owners of beneficial interests in the Global Bonds will receive written confirmation providing details of the transaction, or periodic statements of their holdings, from the Participants through which they purchased beneficial interests in the Global Bonds. The laws of some jurisdictions require that certain purchasers of securities take physical delivery of such securities in definitive form. Such limits and such laws may impair the ability to transfer beneficial interests in the Global Bonds.

So long as DTC, or its nominee, is the registered owner of the Global Bonds, DTC or its nominee, as the case may be, will be considered the sole owner or holder of the bonds represented by the Global Bonds for all purposes under the Master Indenture. Except as set forth below, owners of beneficial interests in the Global Bonds will not be entitled to have bonds registered in their names, will not receive or be entitled to receive physical delivery of the bonds in definitive form and will not be considered the owners or holders thereof under the Master Indenture.

Payment of principal of, premium, if any, and any interest on the bonds represented by the Global Bonds will be made to DTC or its nominee, as the case may be, as the registered owner or the holder of the Global Bonds representing the bonds. None of us, the Master Trustee, any paying agent or the security registrar for the bonds will have any responsibility or liability for any aspect of the records relating to or payments made on account of beneficial ownership interests in the Global Bonds or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

DTC has advised us that, upon receipt of any payment of principal, premium or interest in respect of the Global Bonds, DTC will immediately credit Participants’ accounts with payments in amounts proportionate to their respective beneficial interests in the principal amount of the Global Bonds as shown on the records of DTC. We also expect that payments by Participants to owners of beneficial interests in the Global Bonds held through such Participants will be governed by standing instructions and customary practices, as is now the case with securities held for the accounts of customers in bearer form or registered in “street name” and will be the responsibility of such Participants.

The Global Bonds may not be transferred except as a whole by DTC to a nominee of DTC or by a nominee of DTC to DTC or another nominee of DTC or by DTC or any such nominee to a successor of DTC or a nominee of such successor.

According to DTC, the foregoing information with respect to DTC has been provided to its Participants and other members of the financial community for informational purposes only and is not intended to serve as a representation, warranty, or contract modification of any kind.

Definitive Securities

If DTC is at any time unwilling or unable to continue as depository or if at any time DTC shall no longer be eligible or in good standing under the Exchange Act or other applicable statute or regulation, and we do not appoint a successor depository within ninety days, we will issue definitive bonds (the “Definitive Bonds”) in exchange for the Global Bonds representing the bonds. In addition, we may from time to time in our sole discretion determine that bonds issued or issuable in the form of one or more Global Bonds shall no longer be represented as such Global Bond. In any such instance, an owner of a beneficial interest in the Global Bonds will be entitled to physical delivery of Definitive Bonds represented by the Global Bonds equal in principal amount to such beneficial interest and to have such Definitive Bonds registered in its name.

Restrictions on Transfer

The bonds will be subject to restrictions on transfer and will bear a restrictive legend substantially as described in “Notice to Investors.”

Reports

We currently file reports and other information with the SEC pursuant to the Exchange Act and will covenant to continue to file reports under Sections 13 and 15(d) of the Exchange Act in connection with the issuance of the bonds as long as the bonds are outstanding. During any period in which we are prohibited from filing reports and other information with the SEC under Section 13 or 15(d) under the Exchange Act, we will make available to the holders or beneficial holders of the bonds and prospective purchasers (i) upon their request, the information, if any, required under Rule 144A(d)(4) under the Securities Act until such time as such securities are no longer “restricted securities” within the meaning of Rule 144 under the Securities Act, assuming these securities have not been owned by an affiliate of ours and (ii) unaudited quarterly financial statements within 60 days after the end of each fiscal quarter (except for the fourth quarter of each fiscal year) and audited financial statements within 120 days after the end of each fiscal year.

Description of the Master Indenture

General

The bonds will be issued under our Master Indenture. The terms of the bonds will include those stated in the Master Indenture. The following summary of the Master Indenture is not complete and is subject in all respects to the provisions of, and is qualified in its entirety by reference to, the Master Indenture. We urge you to read the Master Indenture because it, not this description, defines the rights of holders of the bonds. Capitalized terms used in this “Description of the Master Indenture” section which are not otherwise defined shall have the meanings set forth in the Master Indenture. Wherever particular provisions of the Master Indenture or terms defined therein are referred to, those provisions or definitions are incorporated by reference as a part of the statements made in this prospectus and these statements are qualified in their entirety by such reference. References to “Articles” and “Sections,” unless otherwise indicated, are references to article and section numbers of the Master Indenture.

Security

Under the Master Indenture, we granted to the Master Trustee a first mortgage lien on and security interest in the trust estate that is comprised of substantially all of our property, whenever acquired, including real property, electric system equipment, certain contract rights (including our wholesale electric service contracts with our Members, our WAPA power purchase contracts and other power purchase and sale and transmission contracts with a term in excess of one year, fuel contracts, and contracts relating to joint ownership of generation assets), certain general intangibles, and funds, rents and revenues, as well as all proceeds and accounts receivable of the foregoing (collectively, the “Trust Estate”). The Master Indenture provides upon the occurrence of an Event of Default for a “springing lien” on certain property that otherwise is excepted from the lien and security interest of the Master Indenture, including cash and investments, inventories, transportation equipment, certain contracts and current assets. The Master Indenture permits us to exclude certain property from the lien and security interest of the Indenture prior to our acquisition of such property by delivering an officers’ certificate to the Master Trustee stating, among other things, that no default exists, the required ECR (see “Description of the Master Indenture—ECR Covenant”) is met after such acquisition, and no debt is issued and secured under the Master Indenture to finance the acquisition or construction of such excluded property. Assets of our subsidiaries are not pledged under the Master Indenture, except, in certain circumstances, with respect to certain assets of a “Restricted Subsidiary” (there currently are none). For example, the assets of Springerville Partnership, the Owner Lessor, TCP and Elk Ridge are not pledged under the Master Indenture. In addition, certain contracts, including our WAPA power purchase contracts and our leasehold interest in Springerville Unit 3, may not be assumed by a foreclosure purchaser without the approval of the contract counterparty.

As of March 31, 2016, we had approximately \$2.9 billion of outstanding Secured Obligations. The Master Indenture permits us to issue other secured debt (all such debt secured by the Master Indenture constituting “Secured Obligations”), subject in the case of additional Secured Obligations, to meeting certain historic and pro forma financial tests (see “Description of the Master Indenture—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations”). Under the terms of our Master Indenture, the aggregate principal amount of Secured Obligations which may be outstanding at any one time may not exceed \$5 billion; provided we may increase or decrease the maximum aggregate principal amount of Secured Obligations which may be outstanding at any one time without the consent of any secured holders.

Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations

Under the Master Indenture, our Debt Service Ratio is defined, for any period, as the ratio of our Net Margins Available for Debt Service for the period, divided by our Annual Debt Service Requirement for the period (in each case, including any Restricted Subsidiaries). “Net Margins Available for Debt Service” is defined for a fiscal year or other accounting period as the excess of revenues over expenses for the period for us and any Restricted Subsidiary, determined according to Accounting Requirements (as defined in the Master Indenture), 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), amortization of debt discount or premium, lease expense, income tax expense, and depreciation and certain other non-cash items. “Annual Debt Service Requirement” is generally defined to include the principal of, premium, if any, and interest (whether capitalized or expensed) on all of our debt and lease payments and any Restricted Subsidiary’s debt and lease payments which comes due in the year at maturity or stated maturity, and it includes special calculation rules applicable to specific types of debt.

For purposes of the Annual Debt Service Requirement calculation, we are permitted to exclude 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 the debt, in which case the income from such obligations is not included for purposes of calculation of Net Margins Available for Debt Service.

The Master Indenture definition of “debt” excludes certain items including lease obligations which are not categorized as debt under Accounting Requirements. However, rental expense and payments under such lease obligations are required to be taken into account for purposes of the Annual Debt Service Requirement and the Debt Service Ratio calculations.

The Master Indenture obligates us to establish and collect rates and other charges at levels which, together with other revenues, are reasonably expected to cause our Debt Service Ratio to be at least 1.10 on an annual basis. We must report the results of the annual Debt Service Ratio calculation to the Master Trustee within 120 days after the end of each fiscal year. If the Debt Service Ratio as reported to the Master Trustee is below the requirement, we must implement a plan within 60 days that is designed to produce the Debt Service Ratio of at least 1.10.

Our failure to achieve the required Debt Service Ratio is not a default under the Master Indenture as long as a plan is timely adopted and being implemented and no payment default has occurred. However, subject to certain limited exceptions, we cannot issue additional Secured Obligations under the Master Indenture unless the Debt Service Ratio for the prior fiscal year (or period of prior 12 consecutive months) is 1.10 and the estimated Debt Service Ratio for the current and next two fiscal years (or, if applicable, two years following the anticipated commercial operation date of the assets being financed) is 1.10. Further, if the Debt Service Ratio reported to the Master Trustee falls below 1.025, the Master Indenture also provides that our cash receipts are required to be transmitted to the Master Trustee for deposit into a revenue fund or into a separate lockbox account and such proceeds will be applied as provided in the Master Indenture. See “Description of the Master Indenture—Events of Default and Remedies.”

ECR Covenant

Under the Master Indenture, we are required to maintain an ECR at the end of each fiscal year of at least 14 percent for 2015 and 18 percent thereafter. Our ECR equals our equity divided by the sum of our debt and equity. Equity primarily consists of our aggregate net margins that have not been distributed to our Members. Our failure to maintain the ECR for any given year would constitute an Event of Default under the Master Indenture.

Consolidation, Merger or Sale

The Master Indenture generally permits a consolidation or merger between us and another corporation, partnership or trust organization, as well as the sale or transfer by us of the Trust Estate substantially as an entirety. These transactions are permitted if, among other things, (i) no default exists or will exist under the Master Indenture after such transaction, (ii) the acquiring entity is organized under the laws of any domestic jurisdiction, assumes payment of our debt, including our Secured Obligations, and agrees to perform our covenants in the Master Indenture, and (iii) after giving effect to the transaction, the acquiring entity would be able to incur additional Secured Obligations under the Master Indenture.

Insurance

Under our Master Indenture, we are required to maintain insurance on our property of a character usually insured by companies operating similar properties and engaged in similar operations, with responsible insurance carriers or through self-insurance, in accordance with prudent utility practice. The Master Indenture provides that proceeds of such insurance with respect to Mortgaged Property will be paid to the Master Trustee and made available to us to cover the costs of rebuilding or replacing destroyed or damaged Mortgaged Property as long as no default exists under the Master Indenture.

Additional Covenants

The Master Indenture requires us to keep our Trust Estate free of liens and encumbrances other than specified permitted liens and encumbrances.

The Master Indenture permits us to dispose of the Trust Estate free of the lien of the Master Indenture under certain circumstances (including any disposition in the ordinary course of business, provided that, immediately after such disposition, we will continue to meet the ECR required by the Master Indenture); if more than 15 percent of our total assets are disposed of in any year, we are required to use the proceeds of the disposition within one year to either prepay Secured Obligations or acquire electric system assets that will become part of the Trust Estate.

Additionally, we are subject to certain restrictions relating to (a) our issuance of subordinated secured debt and unsecured debt, and (b) our ability to retire patronage capital to our Members during an Event of Default or without satisfying the required ECR following such retirement. Our obligation to comply with certain covenants in the Master Indenture may be waived by the consent or waiver by the holders of the percentage of the principal amount of the Secured Obligations that would be sufficient to amend the specific covenant at issue.

Amendments and Supplements to the Master Indenture

Subject to certain exceptions, the Master Indenture may be amended or supplemented by us and the Master Trustee with the consent of the holders of not less than a majority in principal amount of the Secured Obligations outstanding on the special record date established by the Master Trustee for determining such consents for the purpose of adding provisions to or changing in any manner or eliminating any of the provisions of the Master Indenture or of modifying in any manner the rights of the holders of Secured Obligations.

However, without the consent of the holders of all outstanding Secured Obligations affected thereby, no amendment, supplement or waiver may, among other things:

- reduce the percentage of principal amount of outstanding Secured Obligations whose holders must consent to an amendment, supplement or waiver;

- permit the creation of any lien ranking prior to or on a parity with the lien of the Master Indenture with respect to any of the Trust Estate or terminate the lien of the Master Indenture on any property at any time subject to the Master Indenture or deprive the holder of any Secured Obligation of the security afforded by the lien of the Master Indenture;
- change the stated maturity of the principal or any interest on any Secured Obligation, or reduce the principal amount thereof or the interest thereon or any premium payable upon the redemption thereof;
- impair the right to institute suit for the enforcement of any such payment on any Secured Obligation;
- waive a default or Event of Default in the payment of principal of, premium, if any, or interest on any Secured Obligations; or
- make any change in the amendment or waiver provisions that require holder consent except to increase the percentage of holder consent required thereby or to add other provisions the amendment or waiver of which would require holder consent.

Notwithstanding the foregoing, without the consent of any holder of any Secured Obligations, we and the Master Trustee may from time to time amend or supplement the Master Indenture, in form satisfactory to the Master Trustee, for any of the following purposes:

- to correct or amplify the description of any property at any time subject to the lien of the Master Indenture, or better to assure, convey and confirm unto the Master Trustee any property subject or required to be subjected to the lien of the Master Indenture, or to subject to the lien of the Master Indenture additional property;
- to add to the conditions, limitations and restrictions on the issuance of Secured Obligations;
- to create any series of Secured Obligations;
- to modify, add to, or eliminate any of the terms of the Master Indenture; provided, that, (1) such amendment or supplement expressly provides that any such modifications or eliminations become effective only when there are no Secured Obligations outstanding of any series created prior to the execution of such amendment or supplement; and (2) the Master Trustee may, in its discretion decline to enter into any amendment or supplement which, in its opinion, may not afford adequate protection to the Master Trustee when the same becomes operative;
- to evidence the transfer of the Trust Estate substantially as an entirety as permitted by the Master Indenture (see “Description of the Master Indenture—Consolidation, Merger or Sale”) and the assumption by any such acquiring or surviving entity of our covenants and our other obligations under the Master Indenture and the Secured Obligations;
- to add to our covenants for the benefit of the holders of all Secured Obligations or to surrender any right or power conferred upon us in the Master Indenture;
- to cure any ambiguity or to correct or supplement any provision in the Master Indenture which may be inconsistent with any other provision therein, provided such action shall not adversely affect the interests of the holders of Secured Obligations in any material respects;
- to modify, eliminate or add to the provisions of the Master Indenture to such extent as shall be necessary to effect the qualification of the Master Indenture under the Trust Indenture Act or under any similar federal statute hereafter enacted, or any federal securities laws or the rules of any securities exchange, and to add to the Master Indenture such other provisions as may be

expressly required by the Trust Indenture Act or any federal securities laws or the rules of any securities exchange;

- to provide for any series of Secured Obligations to be issued in bearer form or a book-entry system or uncertificated form;
- to establish special funds or accounts under the Master Indenture;
- to make any changes required by any Rating Agency to maintain the rating on any series of Secured Obligations not inconsistent with the provisions of the Master Indenture;
- to make any change in the Master Indenture that, in our judgment, will not materially adversely affect the holders of the Secured Obligations. For purposes of this change, such amendment or supplement will be presumed to not materially adversely affect the rights of such holders if: (i) the Master Indenture as so amended or supplemented secures equally and ratably the payment of the principal, premium, if any, and interest on the outstanding Secured Obligations which are to remain outstanding; and (ii) we furnish written evidence to the Master Trustee from at least two Rating Agencies that their respective ratings of us will not be withdrawn or reduced as a result of changes in the Master Indenture affected by such amendment or supplement; or
- to increase or decrease the maximum aggregate principal amount of Secured Obligations that may be outstanding at any one time; provided any decrease in such maximum aggregate principal amount shall not be less than 110 percent of the Secured Obligations issued and outstanding at the time of such decrease.

The consent of the holders is not necessary under the Master Indenture to approve the particular form of any proposed amendment or supplement. It is sufficient if such consent approves the substance of the proposed amendment or supplement.

Events of Default and Remedies

The following events constitute “Events of Default” under the Master Indenture:

(a) our default in the payment of principal or premium or in the payment of interest on, or any and all amounts payable under any Secured Obligations (a five-day grace period for receipt of principal or interest may be applied twice in any 12-month period); or

(b) our default in the performance, or breach, of any covenant, agreement, obligation or warranty contained in the Master Indenture, and our failure to remedy such default within 30 days of notice of such default as provided in the Master Indenture; or

(c) the entry against us or any Restricted Subsidiary of a bankruptcy decree or order by a court, or the appointment of a custodian, receiver, liquidator, or other similar official for us or any Restricted Subsidiary or any substantial part of any of our or such Restricted Subsidiary’s property, or the ordering the winding up or liquidation of any of our or such Restricted Subsidiary’s affairs, and the continuance of any such decree or order unstayed and in effect for a period of 60 consecutive days; or

(d) the commencement by us or any Restricted Subsidiary of a voluntary case under the federal bankruptcy code or any other applicable federal or state law, or the consent or acquiescence by us or any Restricted Subsidiary to the filing of any such petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator (or other similar official) of us or any Restricted Subsidiary or any substantial part of any of our or such Restricted Subsidiary’s property, or the making by us or any Restricted

Subsidiary of an assignment for the benefit of creditors, or failure to pay debts generally as they become due, or the taking of corporate action in furtherance of any such action; or

(e) a final judgment is levied against us by a court of competent jurisdiction for any amount in excess of 5 percent of our total assets and such amount remains unpaid after the date it is due, unless such judgment is stayed pending appeal.

In addition, certain of our loan agreements relating to our Secured Obligations provide that upon an event of default thereunder the holders of the applicable Secured Obligations may accelerate the applicable Secured Obligations pursuant to the terms of such loan agreements. Such events of default may be triggered by representations and warranties, covenants and other events beyond the scope of those that may trigger an Event of Default under the Master Indenture. While such declaration of acceleration would not itself result in an Event of Default under the Master Indenture affecting all Secured Obligations equally, if we fail to pay all amounts due upon such acceleration pursuant to the terms of the applicable loan agreement, an Event of Default specified in (a) above will have occurred.

Upon the occurrence of an Event of Default, we would be required, upon written demand of the Master Trustee, to surrender actual possession of the Trust Estate to the Master Trustee until the Event of Default is cured. If an Event of Default specified in (c) and (d) above occurs, the principal amount of all the outstanding Secured Obligations becomes immediately due and payable. If any other Event of Default occurs and is continuing, either the Master Trustee or the holders of at least 25 percent in principal amount of the outstanding Secured Obligations may declare the principal amount of the outstanding Secured Obligations immediately due and payable.

Furthermore, if an Event of Default occurs, the Master Trustee has the power, and may be directed by the holders of a majority in principal amount of the Secured Obligations, to sell the Trust Estate under the Master Indenture. Although the Master Indenture permits any of the Trust Estate to be sold pursuant to judicial proceedings upon an Event of Default, only our Mortgaged Property may be sold pursuant to non-judicial foreclosure (power of sale). In addition, in the event of a non-bankruptcy Event of Default, the Master Trustee may elect to continue to operate our business.

Upon the occurrence of an Event of Default, or if our Debt Service Ratio falls below 1.025 at the end of any fiscal year (or at any other time a calculation of the Debt Service Ratio is required to be made pursuant to the Master Indenture), all of our cash receipts (including cash receipts of any Restricted Subsidiary) are required to be transmitted to the Master Trustee for deposit into a revenue fund or into a separate lockbox account. Assuming the continued operation of our business by the Master Trustee, all moneys deposited into the revenue fund or lockbox account will be applied monthly in the following order of priority:

- first, to the Master Trustee and any paying agent or escrow agent for any fees or expenses payable to them in connection with their services under the Master Indenture;
- second, to us to cover all of the monthly operating expenses of our system that are encumbered by the lien created by the Master Indenture;
- third, to an operating and maintenance reserve account, an amount necessary to maintain the operating and maintenance reserve specified in the Master Indenture;
- fourth, on a pro-rata basis amounts relating to payments due and unpaid, as well as future payments, on principal and interest relating to the Secured Obligations, and other fees of a trustee of related bonds for which we are an obligor;
- fifth, to each holder of Secured Obligations for fees and expenses due and payable on the Secured Obligations; and

- sixth, on a pro-rata basis to each debt service reserve fund established under a supplement to the Master Indenture or an indenture for related bonds, amounts required to restore the relevant debt service reserve fund requirement.

Any amounts remaining after the above distributions are made, as well as any proceeds from the sale of any part of the Trust Estate received by the Master Trustee by virtue of exercising remedies upon an Event of Default, are to be paid in the following order of priority:

- first, to the Master Trustee for any compensation not deducted, expenses and disbursements, and for any amounts owed in connection with our indemnification obligations, if any;
- second, to pay all amounts due and unpaid in connection with the Secured Obligations (if such amounts are insufficient to pay in full the amounts so due and unpaid upon the Secured Obligations, then the payment of such principal, premium, if any, and interest, without preference or priority, ratably according to the aggregate amount due);
- third, to the holders of the Secured Obligations for any fees due under any instrument evidencing the Secured Obligations or any related loan agreement; and
- fourth, any remaining amounts to us, to others entitled to receive such amounts, or as determined by a court.

Any past default under the terms of the Master Indenture and consequences thereof may be waived with the consent of the holders of a majority in principal amount of the Secured Obligations then outstanding, except a default (1) in the payment of the principal of, premium, if any, or interest on any Secured Obligations or (2) in respect of a covenant or provision of the Master Indenture which cannot be modified or amended (as described above under “Description of the Master Indenture—Amendments and Supplements to the Master Indenture”) without the consent of the holder of each outstanding Secured Obligation affected.

Satisfaction and Discharge

The Master Indenture will be discharged and will cease to be of further effect as to the bonds and all other Secured Obligations issued thereunder when we have paid the principal of, premium, if any, and interest and all other amounts due and owing on all the Secured Obligations outstanding (including all of the Master Trustee’s fees and expenses, including attorneys’ fees and expenses). We must also deliver an officers’ certificate and an opinion of counsel to the Master Trustee stating that all conditions precedent to satisfaction and discharge have been satisfied. The Secured Obligations of any series (including the bonds) will be deemed to have been paid if the following conditions are satisfied: (a) if the Secured Obligations are to be redeemed prior to their maturity date, we give the Master Trustee, in form satisfactory to the Master Trustee, irrevocable written instruction to give notice of redemption of such Secured Obligations on the redemption date; (b) we deposit with the Master Trustee sufficient money or Defeasance Obligations (of which the sufficient value is established by an officers’ certificate accompanied by an Independent Accountant’s report) to pay such Secured Obligations in full on the maturity date or redemption date; and (c) in the event such Secured Obligations are not subject to redemption within the next 45 days, we give the Master Trustee, in form satisfactory to the Master Trustee, irrevocable instructions to give a notice to the holders of such Secured Obligations that the deposit described in (b) above has been made to the Master Trustee and that such Secured Obligations are deemed to be paid and stating the maturity date or redemption date, as applicable.

Material U.S. Federal Income Tax Consequences

The following is a discussion of material U.S. federal income tax consequences relevant to the exchange of old bonds for new bonds pursuant to the exchange offer but does not purport to be a complete analysis of all potential tax considerations related to the exchange. The discussion is based on the Internal Revenue Code of 1986, as amended, Treasury Regulations promulgated thereunder, judicial decisions, and published rulings and administrative pronouncements of the U.S. Internal Revenue Service, or IRS, all of which are subject to differing interpretations or change, possibly with retroactive effect. We have not sought and will not seek any rulings from the IRS regarding the matters discussed below. There can be no assurance the IRS or a court will not take a contrary position regarding the tax consequences of the exchange of old bonds for new bonds pursuant to the exchange offer. Some holders, including financial institutions, insurance companies, regulated investment companies, tax-exempt organizations, dealers in securities or currencies, persons whose functional currency is not the U.S. dollar, persons who hold the bonds as part of a hedge, straddle or other risk reduction strategy or as part of a conversion transaction or other integrated investment, or partnerships or other entities or arrangements treated as partnerships for U.S. federal income tax purposes may be subject to special rules not discussed below.

We urge you to consult your own tax advisors regarding the U.S. federal income tax consequences, as well as any other federal, state, local and foreign tax consequences, of the exchange in light of your particular situation.

Exchange of Old Bonds for New Bonds

The exchange of old bonds for new bonds pursuant to the exchange offer will not be treated as a taxable disposition of the old bonds for U.S. federal income tax purposes because the new bonds will not differ materially in kind or extent from the old bonds. Accordingly, for U.S. federal income tax purposes:

- you will not recognize taxable income, gain or loss on the exchange;
- your holding period for the new bonds you receive pursuant to the exchange offer will include your holding period for the old bonds exchanged therefor; and
- your adjusted basis in the new bonds you receive pursuant to the exchange offer will equal your adjusted basis in the old bonds exchanged therefor (as determined immediately prior to the date of exchange).

Plan of Distribution

Each broker-dealer that receives new bonds for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of new bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new bonds received in exchange for old bonds where such old bonds were acquired as a result of market-making activities or other trading activities. We have agreed that, starting on the date of the completion of the exchange offer to which this prospectus relates, for up to 90 days following completion of the exchange offer, we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale.

We will not receive any proceeds from the exchange of old bonds for new bonds or from any sale of new bonds by broker-dealers. New bonds received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the new bonds or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or at negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such new bonds. Any broker-dealer that resells new bonds received for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such new bonds may be deemed to be an “underwriter” within the meaning of the Securities Act and any profit on any such resale of new bonds and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that, by acknowledging that it will deliver a prospectus and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. The letter of transmittal also states that any holder participating in this exchange offer will have no arrangement or understanding with any person to participate in the distribution of the old bonds or the new bonds within the meaning of the Securities Act.

For a period of 90 days after the completion of the exchange offer, we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. We have agreed to pay all expenses incident to the exchange offer (including the expenses of one counsel for the holders of the old bonds) other than commissions or concessions of any brokers or dealers and will indemnify the holders of the old bonds (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

Legal Matters

The validity of the new bonds will be passed upon for us by Dorsey & Whitney LLP, New York, New York.

Experts

The consolidated financial statements of Tri-State Generation and Transmission Association, Inc. at December 31, 2015 and 2014, and for each of the three years in the period ended December 31, 2015, appearing in this prospectus and Registration Statement on Form S-4 have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

Where You Can Find More Information

We have filed with the SEC a Registration Statement on Form S-4 regarding the exchange offer and the new bonds. This prospectus, which constitutes part of the registration statement, does not contain all of the information set forth in the registration statement. For further information regarding us, the exchange offer and the new bonds, please refer to the registration statement and the exhibits filed as part of the registration statement.

The registration statement, including the exhibits, may be inspected and copied at the public reference facilities maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of this material can also be obtained upon written request from the Public Reference Section of the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549, at prescribed rates or from the SEC's website on the Internet at <http://www.sec.gov>. Please call the SEC at 1-800-SEC-0330 for further information on public reference rooms.

We file, on a voluntary basis, annual, quarterly and current reports and other information with the SEC pursuant to the Securities Exchange Act of 1934. These reports and other information may be inspected and copied at the public reference facilities maintained by the SEC or obtained from the SEC's website as provided above.

Calculation of Financial Ratios

Equity to Capitalization Ratio

	As of December 31, 2015
	(\$ in thousands)
<i>ECR</i>	
Total Debt	\$2,845,071
Total Margins & Equities	952,917
Total Capitalization	\$3,797,988
<i>ECR</i>	<u><u>25.1%</u></u>

Debt Service Ratio

	Year Ended December 31, 2015
	(\$ in thousands)
<i>Net Margins Available for Debt Service</i>	
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
<i>Annual Debt Service Requirements</i>	
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
<i>Debt Service Ratio</i>	1.23

Tri-State Generation and Transmission Association, Inc.

Consolidated Financial Statements

Index to Financial Statements

Audited Financial Statements

Report of Independent Auditors	F-2
Consolidated Statements of Financial Position as of December 31, 2015 and 2014	F-3
Consolidated Statements of Operations for the years ended December 31, 2015, 2014 and 2013	F-4
Consolidated Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013	F-5
Consolidated Statements of Equity for the years ended December 31, 2015, 2014 and 2013	F-6
Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013	F-7
Notes to Consolidated Financial Statements	F-8

Unaudited Financial Statements

Consolidated Statements of Financial Position as of March 31, 2016 (unaudited) and December 31, 2015	F-39
Consolidated Statements of Operations—Three Months Ended March 31, 2016 and 2015 (unaudited)	F-40
Consolidated Statements of Comprehensive Income—Three Months Ended March 31, 2016 and 2015 (unaudited)	F-41
Consolidated Statements of Equity—Three Months Ended March 31, 2016 and 2015 (unaudited)	F-42
Consolidated Statements of Cash Flows—Three Months Ended March 31, 2016 and 2015 (unaudited)	F-43
Notes to Consolidated Financial Statements For the Three Months Ended March 31, 2016 and 2015	F-44

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)

<u>For the years ended December 31,</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
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
	<u>1,335,448</u>	<u>1,395,091</u>	<u>1,341,163</u>
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
	<u>1,157,479</u>	<u>1,213,214</u>	<u>1,152,575</u>
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
	<u>17,525</u>	<u>23,333</u>	<u>31,554</u>
Interest expense, net of amounts capitalized	142,570	142,357	149,463
Income taxes	—	—	—
Net margins including noncontrolling interest	<u>52,924</u>	<u>62,853</u>	<u>70,679</u>
Net loss attributable to noncontrolling interest	489	1,383	2,233
Net margins attributable to the Association	<u>\$ 53,413</u>	<u>\$ 64,236</u>	<u>\$ 72,912</u>

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)

<u>For the years ended December 31,</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
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	<u>\$54,830</u>	<u>\$60,073</u>	<u>\$72,832</u>

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)

<u>For the years ended December 31,</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
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	<u>(10,000)</u>	<u>(20,946)</u>	<u>(10,000)</u>
Patronage capital equity at end of year	<u>952,082</u>	<u>908,669</u>	<u>865,379</u>
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	<u>14</u>	<u>31</u>	<u>(358)</u>
Accumulated other comprehensive income (loss) at end of year	<u>589</u>	<u>(828)</u>	<u>3,335</u>
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	<u>(56)</u>	<u>(55)</u>	<u>(54)</u>
Noncontrolling interest at end of year	<u>108,757</u>	<u>109,302</u>	<u>110,740</u>
Total equity at end of year	<u>\$1,061,428</u>	<u>\$1,017,143</u>	<u>\$979,454</u>

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)

<u>For the years ended December 31,</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>
Operating activities	\$ 52,924	\$ 62,853	\$ 70,679
Net margins including noncontrolling interest			
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	(290,428)	(221,613)	(212,703)
Purchases of plant	9,031	(8,263)	(1,849)
Changes in deferred charges	321	15,270	1,578
Proceeds from other investments	(281,076)	(214,606)	(212,974)
Net cash used in investing activities			
Financing activities	(7,041)	2,227	(2,129)
Member advances	(113,063)	(1,739,835)	(196,490)
Payments of long-term debt	240,183	1,674,977	258,873
Proceeds from issuance of debt	—	(184,073)	—
Debt refinancing transaction costs	—	137,727	130,257
Decrease in advance payments to RUS	(8,286)	(20,582)	(10,711)
Retirement of patronage capital	8,931	8,723	8,410
Proceeds from investment in securities pledged as collateral	327	48,000	(15,357)
Change in restricted cash and investments	121,051	(72,836)	172,853
Net cash provided by (used in) financing activities	52,119	(100,589)	111,565
Net increase (decrease) in cash and cash equivalents	92,468	193,057	81,492
Cash and cash equivalents—beginning	\$ 144,587	\$ 92,468	\$ 193,057
Cash and cash equivalents—ending			
Supplemental cash flow information:	<u>\$ 154,657</u>	<u>\$ 152,344</u>	<u>\$ 166,828</u>
Cash paid for interest			
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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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):

	<u>2015</u>	<u>2014</u>
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	—
	<u>415,081</u>	<u>426,043</u>
Regulatory liabilities		
Deferred revenues(7)	<u>45,000</u>	<u>45,000</u>
Net regulatory asset	<u>\$370,081</u>	<u>\$381,043</u>

- (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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

- (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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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):

	<u>2015</u>	<u>2014</u>
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	<u>3,516</u>	<u>3,175</u>
Investments in other associations	<u>\$123,686</u>	<u>\$117,976</u>

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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):

	<u>2015</u>	<u>2014</u>
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	<u>(637)</u>	<u>3,282</u>
Asset retirement obligation at end of year	<u>\$55,215</u>	<u>\$53,754</u>

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

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 meet its obligations as they become due within one year after the date 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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 3—PROPERTY, PLANT AND EQUIPMENT (Continued)

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		<u>\$ 3,462,065</u>	<u>\$ 3,270,160</u>

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 3—PROPERTY, PLANT AND EQUIPMENT (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 4—INTANGIBLES (Continued)

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	<u>3,096</u>
	<u>\$6,221</u>

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 5—LONG-TERM DEBT (Continued)

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

	<u>2015</u>	<u>2014</u>
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	<u>\$3,371,679</u>	<u>\$3,242,470</u>
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	<u>\$3,364,957</u>	<u>\$3,238,048</u>
Less current maturities	(91,419)	(92,802)
Long-term debt	<u>\$3,273,538</u>	<u>\$3,145,246</u>

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 5—LONG-TERM DEBT (Continued)

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		<u>2,633,569</u>
		<u>\$3,364,957</u>

(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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 6—FAIR VALUE (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 7—INCOME TAXES (Continued)

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

	<u>2015</u>	<u>2014</u>	<u>2013</u>
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	<u>(1.17)</u>	<u>(8.36)</u>	<u>(2.37)</u>
Effective tax rate	<u>0.00%</u>	<u>0.00%</u>	<u>0.00%</u>

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 8—LEASES (Continued)

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
	<u>\$48,080</u>

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
	<u>\$23,083</u>

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 9—RELATED PARTIES (Continued)

\$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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

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):

	<u>2015</u>	<u>2014</u>
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	<u>(632)</u>	<u>4,194</u>
Postretirement medical benefit obligation at end of year	\$6,723	\$7,713
Postemployment medical benefit obligation at end of year	<u>178</u>	<u>418</u>
Total postretirement and postemployment medical obligations at end of year	<u>\$6,901</u>	<u>\$8,131</u>

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

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)

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

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	<u>2,600</u>
	<u>\$4,964</u>

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 11—VARIABLE INTEREST ENTITIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 11—VARIABLE INTEREST ENTITIES (Continued)

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	<u>63,396</u>
	<u>\$562,075</u>

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.

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Consolidated Financial Statements (Continued)

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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:

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

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.

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

	March 31, 2016	December 31, 2015
ASSETS		
Property, plant and equipment		
Electric plant		
In service	\$ 5,526,590	\$ 5,486,518
Construction work in progress	212,328	216,279
Total electric plant	5,738,918	5,702,797
Less allowances for depreciation and amortization	(2,268,672)	(2,240,732)
Net electric plant	3,470,246	3,462,065
Other plant	229,528	227,957
Less allowances for depreciation, amortization and depletion	(77,002)	(73,471)
Net other plant	152,526	154,486
Total property, plant and equipment	3,622,772	3,616,551
Other assets and investments		
Investments in other associations	124,578	123,686
Investments in and advances to coal mines	16,718	16,221
Restricted cash and investments	1,000	1,000
Intangible assets	23,803	25,634
Other noncurrent assets	12,171	12,139
Total other assets and investments	178,270	178,680
Current assets		
Cash and cash equivalents	160,743	144,587
Restricted cash and investments	9,512	9,530
Deposits and advances	28,456	21,673
Accounts receivable—Members	89,848	106,216
Other accounts receivable	19,913	14,270
Coal inventory	53,072	59,277
Materials and supplies	86,107	85,501
Total current assets	447,651	441,054
Deferred charges		
Regulatory assets	409,961	415,081
Prepayment—NRECA Retirement Security Plan	47,766	49,146
Other	129,119	122,535
Total deferred charges	586,846	586,762
Total assets	\$ 4,835,539	\$ 4,823,047
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	\$ 969,615	\$ 952,082
Accumulated other comprehensive income	545	589
Noncontrolling interest	108,750	108,757
Total equity	1,078,910	1,061,428
Long-term debt	3,275,624	3,273,538
Total capitalization	4,354,534	4,334,966
Current liabilities		
Member advances	10,143	9,403
Accounts payable	82,255	96,098
Accrued expenses	26,619	30,045
Accrued interest	48,744	34,332
Accrued property taxes	25,903	27,395
Current maturities of long-term debt	92,891	91,419
Total current liabilities	286,555	288,692
Deferred credits and other liabilities		
Regulatory liabilities	45,000	45,000
Deferred income tax liability	28,629	28,629
Intangible liabilities	5,660	6,221
Asset retirement obligations	54,613	55,215
Other	53,521	57,423
Total deferred credits and other liabilities	187,423	192,488
Accumulated postretirement benefit and postemployment obligations	7,027	6,901
Total equity and liabilities	\$ 4,835,539	\$ 4,823,047

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

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

	Three Months Ended March 31,	
	2016	2015
Operating revenues		
Member electric sales	\$271,769	\$267,539
Non-member electric sales	30,122	35,063
Other	21,571	25,789
	323,462	328,391
Operating expenses		
Purchased power	71,035	73,137
Fuel	60,990	61,275
Production	50,982	53,520
Transmission	36,460	37,099
General and administrative	5,110	6,151
Depreciation, amortization and depletion	38,903	34,978
Coal mining	8,273	8,827
Other	5,330	4,020
	277,083	279,007
Operating margins	46,379	49,384
Other income		
Interest income	1,074	1,083
Capital credits from cooperatives	4,511	4,294
Other income	1,041	1,348
	6,626	6,725
Interest expense, net of amounts capitalized	35,420	36,163
Income taxes	—	—
Net margins including noncontrolling interest	17,585	19,946
Net (income) loss attributable to noncontrolling interest	(52)	180
Net margins attributable to the Association	\$ 17,533	\$ 20,126

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

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

	Three Months Ended March 31,	
	2016	2015
Net margins including noncontrolling interest	\$17,585	\$19,946
Other comprehensive loss:		
Unrealized loss on securities available for sale	(22)	(16)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(22)	9
Income tax expense related to components of other comprehensive income (loss)	—	—
Other comprehensive loss	(44)	(7)
Comprehensive income including noncontrolling interest	17,541	19,939
Net comprehensive (income) loss attributable to noncontrolling interest	(52)	180
Comprehensive income attributable to the Association	\$17,489	\$20,119

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

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

	Three Months Ended March 31,	
	2016	2015
Patronage capital equity at beginning of period	\$ 952,082	\$ 908,669
Net margins attributable to the Association	17,533	20,126
Patronage capital equity at end of period	969,615	928,795
Accumulated other comprehensive income (loss) at beginning of period	589	(828)
Unrealized loss on securities available for sale	(22)	(16)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(22)	9
Accumulated other comprehensive income (loss) at end of period	545	(835)
Noncontrolling interest at beginning of period	108,757	109,302
Net income (loss) attributable to noncontrolling interest	52	(180)
Equity distribution to noncontrolling interest	(59)	—
Noncontrolling interest at end of period	108,750	109,122
Total equity at end of period	\$1,078,910	\$1,037,082

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

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

	Three Months Ended March 31,	
	2016	2015
Operating activities		
Net margins including noncontrolling interest	\$ 17,585	\$ 19,946
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	38,903	34,978
Amortization of intangible asset	1,831	1,831
Amortization of NRECA Retirement Security Plan prepayment	1,343	1,380
Amortization of debt issuance costs	470	465
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,703)	(2,673)
Changes in operating assets and liabilities:		
Accounts receivable	10,224	18,660
Coal inventory	6,205	(9,506)
Materials and supplies	(606)	(2,832)
Accounts payable and accrued expenses	(15,729)	12,414
Accrued interest	14,412	15,119
Accrued property taxes	(1,492)	(1,068)
Other	(10,220)	(1,617)
Net cash provided by operating activities	61,223	87,097
Investing activities		
Purchases of plant	(40,326)	(69,788)
Changes in deferred charges	(5,171)	(6,912)
Proceeds from other investments	313	413
Net cash used in investing activities	(45,184)	(76,287)
Financing activities		
Member advances	(438)	(3,286)
Payments of long-term debt	(41,247)	(58,283)
Proceeds from issuance of debt	45,000	39,654
Retirement of patronage capital	(2,879)	(4,213)
Other	(319)	—
Net cash provided by (used in) financing activities	117	(26,128)
Net increase (decrease) in cash and cash equivalents	16,156	(15,318)
Cash and cash equivalents—beginning	144,587	92,468
Cash and cash equivalents—ending	\$160,743	\$ 77,150
Supplemental cash flow information:		
Cash paid for interest	<u>\$ 24,647</u>	<u>\$ 24,132</u>
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	<u>\$ (2,369)</u>	<u>\$ 4,644</u>

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements
For the Three Months Ended March 31, 2016 and 2015

NOTE 1—PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three months ended March 31, 2016 and 2015 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

Our consolidated financial statements include the accounts of Tri-State Generation and Transmission Association, Inc., our wholly-owned and majority-owned subsidiaries and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 10—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.

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 Yampa Project (operated by us), the Missouri Basin Power Project (“MBPP”) (operated by Basin Electric Power Cooperative (“Basin”)) and the San Juan Project (operated by Public Service Company of New Mexico). 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.

Our share in each jointly owned facility is as follows as of March 31, 2016 (thousands):

	<u>Tri-State Share</u>	<u>Electric Plant in Service</u>	<u>Accumulated Depreciation</u>	<u>Construction Work In Progress</u>
Yampa Project—Craig Station Units 1 and 2	24.00%	\$344,987	\$229,132	\$25,562
MBPP—Laramie River Station	24.13%	394,484	289,719	10,989
San Juan Project—San Juan Unit 3	8.20%	<u>82,692</u>	<u>64,024</u>	—
Total		<u>\$822,163</u>	<u>\$582,875</u>	<u>\$36,551</u>

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 2—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 of Directors (“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 that we expect to recover from our member distribution systems (“Members”) through 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):

	<u>March 31, 2016</u>	<u>December 31, 2015</u>
Regulatory assets		
Deferred income tax expense(1)	\$ 28,629	\$ 28,629
Deferred prepaid lease expense—Craig 3 Lease(2)	14,565	16,183
Deferred prepaid lease expense—Springerville 3 Lease(3)	92,305	92,878
Goodwill—J.M. Shafer(4)	59,829	60,541
Goodwill—Colowyo Coal(5)	41,068	41,327
Deferred debt prepayment transaction costs(6)	173,287	175,444
Other	278	79
	<u>409,961</u>	<u>415,081</u>
Regulatory liabilities		
Deferred revenues(7)	45,000	45,000
Net regulatory asset	<u>\$364,961</u>	<u>\$370,081</u>

- (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 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.

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 2—ACCOUNTING FOR RATE REGULATION (Continued)

- (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 received 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.

NOTE 3—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.

NOTE 4—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 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 March 31, 2016, the entire \$8.6 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.

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 4—RESTRICTED CASH AND INVESTMENTS (Continued)

Restricted cash and investments are as follows (thousands):

	<u>March 31, 2016</u>	<u>December 31, 2015</u>
Investments in securities pledged as collateral	\$ 8,629	\$ 8,671
Funds restricted by contract	883	859
Restricted cash and investments—current	<u>9,512</u>	<u>9,530</u>
Funds restricted by contract	<u>1,000</u>	<u>1,000</u>
Restricted cash and investments—noncurrent	<u>1,000</u>	<u>1,000</u>
Total restricted cash and investments	<u>\$10,512</u>	<u>\$10,530</u>

NOTE 5—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 March 31, 2016, preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Station Project of \$88.0 million.

We make advance payments to the operating agents of jointly owned facilities.

Other deferred charges are as follows (thousands):

	<u>March 31, 2016</u>	<u>December 31, 2015</u>
Preliminary surveys and investigations	\$108,567	\$107,146
Advances to operating agents of jointly owned facilities	16,871	11,537
Other	3,681	3,852
Total other deferred charges	<u>\$129,119</u>	<u>\$122,535</u>

NOTE 6—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 \$54.2 million as of March 31, 2016. 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 debt service ratio requirement and equity to capitalization ratio requirement.

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 6—LONG-TERM DEBT (Continued)

We have a secured revolving credit facility with Bank of America, N.A. and CoBank, ACB as Joint Lead Arrangers in the amount of \$750 million (“Revolving Credit Agreement”). We had outstanding borrowings of \$316 million and \$271 million at March 31, 2016 and December 31, 2015, 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. As of March 31, 2016, we have \$386 million in availability under the Revolving Credit Agreement.

Debt issuance costs are accounted for as a direct deduction of the associated long-term debt carrying amount consistent with the accounting for debt discounts and premiums. Debt issuance costs are amortized to interest expense using an effective interest method over the life of the respective debt.

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

	<u>March 31, 2016</u>	<u>December 31, 2015</u>
Total debt	\$3,375,431	\$3,371,679
Less debt issuance costs	(20,731)	(21,201)
Less debt discounts	(8,698)	(8,739)
Plus debt premiums	<u>22,513</u>	<u>23,218</u>
Total debt adjusted for discounts, premiums and debt issuance costs	3,368,515	3,364,957
Less current maturities	<u>(92,891)</u>	<u>(91,419)</u>
Long-term debt	<u>\$3,275,624</u>	<u>\$3,273,538</u>

NOTE 7—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.

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 7—ASSET RETIREMENT OBLIGATIONS (Continued)

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):

	<u>March 31, 2016</u>	<u>December 31, 2015</u>
Asset retirement obligation at beginning of period	\$55,215	\$53,754
Liabilities incurred	—	1,802
Liabilities settled	(413)	(3,028)
Accretion expense	665	3,324
Change in cash flow estimate	<u>(854)</u>	<u>(637)</u>
Asset retirement obligation at end of period	<u>\$54,613</u>	<u>\$55,215</u>

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

NOTE 8—INCOME TAXES

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. 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. We had no income tax expense or benefit for the three months ended March 31, 2016 and 2015.

NOTE 9—FAIR VALUE

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal or in the most advantageous market when no principal market exists. The fair value 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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 9—FAIR VALUE (Continued)

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 March 31, 2016		As of December 31, 2015	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Marketable securities	<u>\$859</u>	<u>\$966</u>	<u>\$1,022</u>	<u>\$1,151</u>

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 March 31, 2016 and December 31, 2015 are reported as a component of accumulated other comprehensive income as of those dates.

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 9—FAIR VALUE (Continued)

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):

	As of March 31, 2016		As of December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	\$3,375,431	\$3,797,978	\$3,371,679	\$3,616,946

NOTE 10—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 \$848.1 million and \$853.3 million at March 31, 2016 and December 31, 2015, respectively, the long-term debt of \$473.5 million and \$511.0 million at March 31, 2016 and December 31, 2015, respectively, accrued interest associated with the long-term debt of \$5.4 million and \$14.3 million at March 31, 2016 and December 31, 2015, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of \$108.8 million at March 31, 2016 and December 31, 2015.

Our consolidated statements of operations include the Springerville Partnership’s depreciation and amortization expense of \$5.3 million for the three months ended March 31, 2016 and the comparable period in 2015. Our consolidated statements of operations also include interest expense of \$7.7 million for the three months ended March 31, 2016 and \$8.2 million for the comparable period in 2015. The net income and losses attributable to the 49 percent noncontrolling equity interest in the Springerville

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 10—VARIABLE INTEREST ENTITIES (Continued)

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, Inc. (“WFA”): 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 Western Fuels-Wyoming. 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. Therefore, since there is shared power over the significant activities of WFA, we are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was \$2.7 million at March 31, 2016 and \$2.3 million December 31, 2015, respectively, and is included in investments in other associations.

Western Fuels—Wyoming (“WFW”): 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”): Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Generating 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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 10—VARIABLE INTEREST ENTITIES (Continued)

for the operation of the Trapper Mine. There isn't sufficient equity at risk for Trapper Mining to finance its activities without the 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 \$14.2 million at March 31, 2016 and \$14.1 million at December 31, 2015.

NOTE 11—LEGAL

On February 17, 2016, we filed a Petition for Declaratory Order with the United States Federal Energy Regulatory Commission ("FERC") seeking a declaratory order from FERC finding that the fixed cost recovery mechanism in our proposed revised Board policy is consistent with the provisions of Public Utility Regulatory Policies Act of 1978, as amended 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. On March 10, 2016, we filed a supplement to our petition providing that our Board adopted the revised Board policy on March 2, 2016. Motions to intervene or protests were due on or before March 25, 2016. Various individuals and entities filed comments and four entities filed motions to intervene, including our Member, Delta-Montrose Electric Association ("DMEA"). On April 8, 2016, we filed a Motion for Leave and Answer in response to motions to intervene and protests. On April 25, 2016, DMEA filed a Motion to Answer and Answer in response to our motion. Because of the early nature of the proceedings, we are unable to project the outcome of this matter although we do not believe it is likely to have a material adverse effect on our financial condition or our future results of operations or cash flows.

NOTE 12—NEW ACCOUNTING PRONOUNCEMENTS

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. This amendment 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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 12—NEW ACCOUNTING PRONOUNCEMENTS (Continued)

expedients. We are currently evaluating the impact of this amendment on our financial position and 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 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 meet its obligations as they become due within one year after the date 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 May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, as amended by subsequent ASU amendments issued in 2015 and 2016. 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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements (Continued)
For the Three Months Ended March 31, 2016 and 2015

NOTE 12—NEW ACCOUNTING PRONOUNCEMENTS (Continued)

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.



A Touchstone Energy® Cooperative 

The Touchstone Energy logo consists of three stylized human figures in red, blue, and orange, standing on a green curved base that resembles a horizon or a path.

Until _____, 2016, all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.



PART II.

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 20. Indemnification of Directors and Officers

Tri-State Generation and Transmission Association, Inc. is incorporated under the laws of the State of Colorado.

Pursuant to Section 7-109-102 of the Colorado Business Corporation Act, or the CBCA, a Colorado corporation may indemnify a person made a party to a proceeding by reason of the former or present official capacity of the person as a director, officer, employee, fiduciary or agent with respect to such Colorado corporation against judgments, penalties, fines, including, without limitation, excise taxes assessed against the person with respect to an employee benefit plan, settlements and reasonable expenses, including attorneys' fees and disbursements, incurred by the person in connection with the proceeding, which we collectively refer to as losses, if such person: (1) has not been adjudged liable to the corporation; (2) acted in good faith; (3) received no improper personal benefit; (4) in the case of a criminal proceeding, had no reasonable cause to believe the conduct was unlawful; and (5) in the case of acts or omissions occurring in the person's official capacity as a director, the person reasonably believed that the conduct was in the best interests of the corporation, or in all other cases, reasonably believed that the conduct was not opposed to the best interests of the corporation. In the case of conduct related to employee benefit plans, a corporation may indemnify a person acting in the person's official capacity as a director, officer, employee, fiduciary or agent for a purpose the person reasonably believed to be in the interests of the participants in or beneficiaries of the plan.

Pursuant to Section 7-109-104 of the CBCA, a Colorado corporation may pay for or reimburse the reasonable expenses of a director, officer, employee, fiduciary or agent who is part of a proceeding by reason of the former or present official capacity of the person with respect to such Colorado corporation if: (1) the person furnishes a written affirmation of the person's good faith belief that the person has met the standard of conduct under Section 7-109-102; (2) the person has furnished an undertaking to repay the advance if it is ultimately determined the person did not meet the standard of conduct in Section 7-109-102 and (3) the Colorado corporation determines that based on the facts currently known, indemnification would not be precluded.

Section 7-109-103 of the CBCA requires a Colorado corporation to indemnify a director or officer against losses who was wholly successful in the defense of the proceedings described above.

Item 21. Exhibits and Financial Statement Schedules

(a) *List of 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 filed on April 22, 2014, File No. 333-203560.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016, File No. 333-203560.)

Exhibit Number	Description
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 filed on April 22, 2014, File No. 333-203560.)
4.1.1†	Supplemental Master Mortgage Indenture No. 39, dated and effective as of May 23, 2016, between Tri State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.2†	Exchange and Registration Rights Agreement, dated May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc. and Wells Fargo Securities, LLC (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.3	Form of Exchange Bond for 4.25% First Mortgage Bonds, Series 2016A, due 2046
4.4.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.4.2*	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
4.5.1*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.5.2*	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
4.5.3*	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
4.5.4*	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
4.5.5*	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
4.6.1*	Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.6.2*	First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997

Exhibit Number	Description
4.6.3*	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
4.6.4*	Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.6.5*	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
4.7.1*	Loan Agreement, dated July 21, 2013, between Tri-State and Basin Electric Power Cooperative
4.7.2*	Promissory Note, dated July 21, 2013, from Tri-State to Basin Electric Power Cooperative, in the original amount of \$850,000
4.8.1*	Master Loan Agreement, dated June 8, 2006, between Tri-State and CoBank, ACB
4.8.2*	Amendment to Master Loan Agreement, dated June 8 2006, between Tri-State and CoBank, ACB related to Loan No. ML0303T5
4.8.3*	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
4.9.1*	Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.9.2*	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
4.10.1*	Unsecured Term Loan Agreement, dated June 10, 2013, between Tri-State and CoBank, ACB
4.10.2*	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
4.11.1*	Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.11.2*	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
4.11.3*	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
4.12.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.12.2*	Secured Promissory note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077
4.13.1*	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-0047-9078

Exhibit Number	Description
4.14*	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.
4.15*	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.
4.16.1*	Notes, dated April 8, 2009, from Tri-State to various purchasers, relating to Series 2009C Note Purchase Agreement
4.16.2*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.17.1*	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
4.17.2*	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
4.18*	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
4.19.1*	Security Agreement, dated June 1, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.2*	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
4.19.3*	Security Agreement, dated July 7, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.4*	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
4.19.5*	Security Agreement, dated March 25, 2011, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.6*	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
4.20.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of \$400,000,000
4.20.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of \$100,000,000

Exhibit Number	Description
4.20.3†	Form of Exchange Bond for Tri-State First Mortgage Bond, dated September 3, 2015, related to Series 2014E-1 due in 2024, in the principal amount of \$250,000,000 (Filed as Exhibit 4.3 to the Registrant’s Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
4.20.4†	Form of Exchange Bond for Tri-State First Mortgage Bond, dated September 3, 2015, related to Series 2014E-2 due in 2044, in the principal amount of \$250,000,000 (Filed as Exhibit 4.4 to the Registrant’s Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
5.1	Opinion of Dorsey & Whitney LLP
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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, File No. 333-203560.)

Exhibit Number	Description
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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, File No. 333-203560.)
10.10†	Form of Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 13, 2016, File No. 333-203560.)
10.11**†	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 filed on April 22, 2014, File No. 333-203560.)
10.12**†	Executive Benefit Restoration Plan, dated December 12, 2014 (Filed as Exhibit 10.18 to the Registrant's Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
10.13**†	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 filed on April 22, 2014, File No. 333-203560.)
12.1	Statement re: Computation of Ratios
21.1	Subsidiaries of Tri-State Generation and Transmission Association, Inc.
23.1	Consent of Ernst & Young LLP
23.2	Consent of Dorsey & Whitney LLP (included in Exhibit 5.1)
24.1	Power of Attorney (included on signature page hereto)
25.1	Statement of Eligibility Under the Trust Indenture Act of 1939 on Form T-1 of Wells Fargo Bank, National Association, as trustee under the Master Indenture
99.1	Form of Letter of Transmittal
99.2	Form of Notice of Guaranteed Delivery
99.3	Form of Letter to Clients

Exhibit Number	Description
99.4	Form of Letter to Depository Trust Company Participants
101	XBRL Interactive Data File.

* 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.

† Previously filed.

Item 22. Undertakings

(a) The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by Section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represent no more than a 20 percent change in the maximum aggregate offering price set forth in the "Calculation of Registration Fee" table in the effective registration statement; and

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial *bona fide* offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

(4) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser:

(i) Each prospectus filed pursuant to Rule 424(b) as part of the registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. *Provided, however,* that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the

registration statement or made in any such document immediately prior to such date of first use.

(5) That, for the purpose of determining liability of such registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities:

The undersigned registrant undertakes that in a primary offering of securities of such registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, such registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrants relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of such registrant or used or referred to by the undersigned registrants;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrants or their securities provided by or on behalf of the undersigned registrants; and

(iv) Any other communication that is an offer in the offering made by such registrant to the purchaser.

(b) Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrants pursuant to the foregoing provisions, or otherwise, the registrants have been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, such registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(c) The undersigned registrant hereby undertakes to respond to requests for information that is incorporated by reference into the prospectus pursuant to Items 4, 10(b), 11, or 13 of this form, within one business day of receipt of such request, and to send the incorporated documents by first class mail or other equally prompt means. This includes information contained in documents filed subsequent to the effective date of the registration statement through the date of responding to the request.

(d) The undersigned registrant hereby undertakes to supply by means of a post-effective amendment all information concerning a transaction, and the company being acquired involved therein, that was not the subject of and included in the registration statement when it became effective.

SIGNATURES

Pursuant to the requirements of the Securities Act, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Westminster, State of Colorado, on June 14, 2016.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By: /s/ MICHEAL S. MCINNES

Name: Micheal S. McInnes

Title: *Chief Executive Officer*

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below hereby severally constitutes and appoints each of Rick Gordon, Micheal S. McInnes and Patrick L. Bridges as his or her true and lawful attorney-in-fact and agent, each with the power of substitution and resubstitution, for him or her in any and all capacities, to sign any and all amendments to this registration statement on Form S-4 (and all further amendments, including post-effective amendments thereto), and to file the same, with accompanying exhibits and other related documents, with the Securities and Exchange Commission, and ratify and confirm all that said attorney-in-fact and agent, or his substitute or substitutes, may lawfully do or cause to be done by virtue of said appointment.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ MICHEAL S. MCINNES</u> Micheal S. McInnes	Chief Executive Officer (principal executive officer)	June 14, 2016
<u>/s/ PATRICK L. BRIDGES</u> Patrick L. Bridges	Senior Vice President/Chief Financial Officer (principal financial officer)	June 14, 2016
<u>/s/ STEVEN J. LINDBECK</u> Steven J. Lindbeck	Senior Manager Controller (principal accounting officer)	June 14, 2016
<u>/s/ RICK GORDON</u> Rick Gordon	Chairman, President and Director	June 14, 2016
<u>/s/ JOSEPH WHEELING</u> Joseph Wheeling	Director	June 14, 2016

<u>Signature</u>	<u>Title</u>	<u>Date</u>
_____ /s/ LEO BREKEL Leo Brekel	Director	June 14, 2016
_____ /s/ STUART MORGAN Stuart Morgan	Director	June 14, 2016
_____ /s/ MATT M. BROWN Matt M. Brown	Director	June 14, 2016
_____ /s/ JULIE KILTY Julie Kilty	Director	June 14, 2016
_____ /s/ HAL KEELER Hal Keeler	Director	June 14, 2016
_____ /s/ WILLIAM MOLLENKOPF William Mollenkopf	Director	June 14, 2016
_____ /s/ TIMOTHY RABON Timothy Rabon	Director	June 14, 2016
_____ /s/ ROBERT BLEDSOE Robert Bledsoe	Director	June 14, 2016
_____ /s/ JERRY BURNETT Jerry Burnett	Director	June 14, 2016
_____ /s/ TONY CASADOS Tony Casados	Director	June 14, 2016
_____ /s/ RICHARD CLIFTON Richard Clifton	Director	June 14, 2016

<u>Signature</u>	<u>Title</u>	<u>Date</u>
_____ /s/ ARTHUR W. CONNELL Arthur W. Connell	Director	June 14, 2016
_____ /s/ LUCAS CORDOVA, JR. Lucas Cordova, Jr.	Director	June 14, 2016
_____ /s/ JOHN FINNERTY John Finnerty	Director	June 14, 2016
_____ /s/ GARY FUCHSER Gary Fuchser	Director	June 14, 2016
_____ /s/ JOHN GAVAN John Gavan	Director	June 14, 2016
_____ Jack Hammond	Director	
_____ /s/ RONALD HILKEY Ronald Hilkey	Director	June 14, 2016
_____ /s/ RALPH HILYARD Ralph Hilyard	Director	June 14, 2016
_____ /s/ DONALD KAUFMAN Donald Kaufman	Director	June 14, 2016
_____ /s/ DONALD KEAIRNS Donald Keairns	Director	June 14, 2016
_____ /s/ THAINE MICHIE Thaine Michie	Director	June 14, 2016

<u>Signature</u>	<u>Title</u>	<u>Date</u>
_____ /s/ VIRGINIA MONDRAGON Virginia Mondragon	Director	June 14, 2016
_____ /s/ CHRISTOPHER MORGAN Christopher Morgan	Director	June 14, 2016
_____ /s/ RICHARD NEWMAN Richard Newman	Director	June 14, 2016
_____ /s/ STANLEY PROPP Stanley Propp	Director	June 14, 2016
_____ /s/ GARY RINKER Gary Rinker	Director	June 14, 2016
_____ /s/ ARTHUR RODARTE Arthur Rodarte	Director	June 14, 2016
_____ /s/ CLAUDIO ROMERO Claudio Romero	Director	June 14, 2016
_____ /s/ DONALD RUSSELL Donald Russell	Director	June 14, 2016
_____ /s/ BRIAN SCHLAGEL Brian Schlagel	Director	June 14, 2016
_____ Donald Schutz	Director	
_____ /s/ JACK SIBOLD Jack Sibold	Director	June 14, 2016

<u>Signature</u>	<u>Title</u>	<u>Date</u>
_____ /s/ CHARLES J. SOEHNER Charles J. Soehner	Director	June 14, 2016
_____ /s/ DARRYL SULLIVAN Darryl Sullivan	Director	June 14, 2016
_____ /s/ JERRY THOMPSON Jerry Thompson	Director	June 14, 2016
_____ /s/ CARL TRICK II Carl Trick II	Director	June 14, 2016
_____ /s/ DOUGLAS SHAWN TURNER Douglas Shawn Turner	Director	June 14, 2016
_____ /s/ DONALD WOLBERG Donald Wolberg	Director	June 14, 2016
_____ /s/ SCOTT WOLFE Scott Wolfe	Director	June 14, 2016
_____ /s/ WILLIAM WRIGHT William Wright	Director	June 14, 2016
_____ /s/ PHILLIP ZOCHOL Phillip Zochol	Director	June 14, 2016

Exhibit Index

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 filed on April 22, 2014, File No. 333-203560.)
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc. (Filed as Exhibit 3.2 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016, File No. 333-203560.)
4.1†	Indenture, dated effective as of December 15, 1999, between Tri-State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) Trustee, as supplemented by Supplemental Indenture No. 2, dated June 30, 2000, Supplemental Indenture No. 20, dated July 30, 2009, Supplemental Indenture No. 21, dated October 8, 2009, Supplemental Indenture No. 27, dated July 29, 2011, Supplemental Indenture No. 28, dated March 15, 2012, Supplemental Indenture No. 29, dated December 6, 2012, Supplemental Indenture No. 30, dated July 3, 2013, Supplemental Indenture No. 34, dated October 30, 2014 and Supplemental Indenture No. 38, dated November 21, 2014 (Filed as Exhibit 4.1 to the Registrant's Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
4.1.1†	Supplemental Master Mortgage Indenture No. 39, dated and effective as of May 23, 2016, between Tri State Generation and Transmission Association, Inc. and Wells Fargo Bank, National Association as (successor) trustee (Filed as Exhibit 4.1 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.2†	Exchange and Registration Rights Agreement, dated May 23, 2016, between Tri-State Generation and Transmission Association, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, U.S. Bancorp Investments, Inc. and Wells Fargo Securities, LLC (Filed as Exhibit 4.2 to the Registrant's Form 8-K filed on May 23, 2016, File No. 333-203560.)
4.3	Form of Exchange Bond for 4.25% First Mortgage Bonds, Series 2016A, due 2046
4.4.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.4.2*	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
4.5.1*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.5.2*	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
4.5.3*	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
4.5.4*	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

Exhibit Number	Description
4.5.5*	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
4.6.1*	Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.6.2*	First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997
4.6.3*	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
4.6.4*	Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.6.5*	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
4.7.1*	Loan Agreement, dated July 21, 2013, between Tri-State and Basin Electric Power Cooperative
4.7.2*	Promissory Note, dated July 21, 2013, from Tri-State to Basin Electric Power Cooperative, in the original amount of \$850,000
4.8.1*	Master Loan Agreement, dated June 8, 2006, between Tri-State and CoBank, ACB
4.8.2*	Amendment to Master Loan Agreement, dated June 8 2006, between Tri-State and CoBank, ACB related to Loan No. ML0303T5
4.8.3*	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
4.9.1*	Term Loan Agreement, dated December 6, 2012, between Tri-State and CoBank, ACB
4.9.2*	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
4.10.1*	Unsecured Term Loan Agreement, dated June 10, 2013, between Tri-State and CoBank, ACB
4.10.2*	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
4.11.1*	Term Loan Agreement, dated October 31, 2014, between Tri-State and CoBank, ACB
4.11.2*	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
4.11.3*	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
4.12.1*	Loan Agreement, dated October 31, 2014, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.12.2*	Secured Promissory note, dated October 31, 2014, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to Loan C-0047-9077

Exhibit Number	Description
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-0047-9078
4.14*	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.
4.15*	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.
4.16.1*	Notes, dated April 8, 2009, from Tri-State to various purchasers, relating to Series 2009C Note Purchase Agreement
4.16.2*	Notes, dated October 31, 2014, from Tri-State to various purchasers, relating to Series 2014B Note Purchase Agreement
4.17.1*	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
4.17.2*	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
4.18*	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
4.19.1*	Security Agreement, dated June 1, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.2*	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
4.19.3*	Security Agreement, dated July 7, 2010, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.4*	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
4.19.5*	Security Agreement, dated March 25, 2011, from Western Fuels-Colorado, A Limited Liability Company to Wells Fargo Equipment Finance, Inc.
4.19.6*	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

Exhibit Number	Description
4.20.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of \$400,000,000
4.20.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of \$100,000,000
4.20.3†	Form of Exchange Bond for Tri-State First Mortgage Bond, dated September 3, 2015, related to Series 2014E-1 due in 2024, in the principal amount of \$250,000,000 (Filed as Exhibit 4.3 to the Registrant's Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
4.20.4†	Form of Exchange Bond for Tri-State First Mortgage Bond, dated September 3, 2015, related to Series 2014E-2 due in 2044, in the principal amount of \$250,000,000 (Filed as Exhibit 4.4 to the Registrant's Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
5.1	Opinion of Dorsey & Whitney LLP
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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, File No. 333-203560.)

Exhibit Number	Description
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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, 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 filed on April 22, 2014, File No. 333-203560.)
10.10†	Form of Commercial Paper Dealer Agreement between Tri-State, as issuer, and the Dealer party thereto (Filed as Exhibit 10.1 to the Registrant's Form 8-K filed on May 13, 2016, File No. 333-203560.)
10.11**†	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 filed on April 22, 2014, File No. 333-203560.)
10.12**†	Executive Benefit Restoration Plan, dated December 12, 2014 (Filed as Exhibit 10.18 to the Registrant's Form S-4 Registration Statement filed on April 22, 2014, File No. 333-203560.)
10.13**†	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 filed on April 22, 2014, File No. 333-203560.)
12.1	Statement re: Computation of Ratios
21.1	Subsidiaries of Tri-State Generation and Transmission Association, Inc.
23.1	Consent of Ernst & Young LLP
23.2	Consent of Dorsey & Whitney LLP (included in Exhibit 5.1)
24.1	Power of Attorney (included on signature page hereto)

Exhibit Number	Description
25.1	Statement of Eligibility Under the Trust Indenture Act of 1939 on Form T-1 of Wells Fargo Bank, National Association, as trustee under the Master Indenture
99.1	Form of Letter of Transmittal
99.2	Form of Notice of Guaranteed Delivery
99.3	Form of Letter to Clients
99.4	Form of Letter to Depository Trust Company Participants
101	XBRL Interactive Data File.

* 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.

† Previously filed.