As filed with the Securities and Exchange Commission on June 18, 2015

Registration No. 333-203560

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 1
to
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	**4911**	**84-0464189**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(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 ☒ (Do not check if a smaller reporting company) 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
3.70% First Mortgage Bonds, Series 2014E-1, due 2024	$250,000,000	100%	$250,000,000	$29,050(2)
4.70% First Mortgage Bonds, Series 2014E-2, due 2044	$250,000,000	100%	$250,000,000	$29,050(2)

(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.

(2) Previously paid.

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 18, 2015

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.

PROSPECTUS

TRI STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

Offer to Exchange

$250,000,000 aggregate principal amount of 3.70% First Mortgage Bonds, Series 2014E-1, due 2024 that have been registered under the Securities Act of 1933 for any and all outstanding unregistered 3.70% First Mortgage Bonds, Series 2014E-1, due 2024

and

$250,000,000 aggregate principal amount of 4.70% First Mortgage Bonds, Series 2014E-2, due 2044 that have been registered under the Securities Act of 1933 for any and all outstanding unregistered 4.70% First Mortgage Bonds, Series 2014E-2, due 2044

We are offering to exchange (i) an aggregate principal amount of $250,000,000 of registered 3.70% First Mortgage Bonds, Series 2014E-1, due 2024, or the new 2014E-1 bonds, for any and all of our outstanding unregistered 3.70% First Mortgage Bonds, Series 2014E-1, due 2024, or the old 2014E-1 bonds, that were issued in a private offering on October 30, 2014 and (ii) an aggregate principal amount of $250,000,000 of registered 4.70% First Mortgage Bonds, Series 2014E-2, due 2044, or the new 2014E-2 bonds, for any and all of our outstanding unregistered 4.70% First Mortgage Bonds, Series 2014E-2, due 2044, or the old 2014E-2 bonds, that were issued in a private offering on October 30, 2014. We refer to the new 2014E-1 bonds and the new 2014E-2 bonds collectively as the new bonds, and we refer to the old 2014E-1 bonds and the old 2014E-2 bonds collectively as the old bonds.

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   , 2015, 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   , 2015

Table of Contents

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, 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, 2015, we sold 3.8 million MWhs to Members and 591,324 MWhs to non-members. In 2014, we sold 15.4 million MWhs to our Members and 3.3 million MWhs to non-members. Total revenue from electric sales was $1.3 billion for 2014 and $302.6 million for the three months ended March 31, 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, 2015, 16 Members have enrolled in this program with capacity totaling approximately 68 MWs.

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 2,843 MWs, including 1,874 MWs from coal-fired base load facilities and 969 MWs from gas-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 194 MWs from renewable energy resources including wind, solar and small hydro. 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 5,400 miles of high-voltage transmission lines and own approximately 225 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 Indenture requires us to maintain an Equity to Capitalization Ratio (as defined in the Master Indenture and as below described, "ECR") at the end of each fiscal year of 14 percent in 2014 and 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, including amounts deposited in our United States Department of Agriculture's Rural Utilities Service, or RUS, cushion of credit account. See "Description of the Master Indenture."

As of December 31, 2014, our ECR was 25.2 percent. See 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 the Master Indenture and as below described, "DSR") of at least 1.10 on an annual basis.

Our DSR is calculated by dividing (x) our Net Margins Available for Debt Service (as defined in the 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, 2014, our DSR was 1.34. See Appendix A—Calculation of Financial Ratios.

Rate Setting

We provide electric power to our Members at rates established by our Board of Directors. 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 of Directors are generally not subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rates to the New Mexico Public Regulation Commission, or the NMPRC. We are also involved in proceedings pending in New Mexico and Colorado regarding efforts by the NMPRC and the Colorado Public Utilities Commission, or the COPUC, related to our wholesale rates payable by our Members. Both the New Mexico and Colorado proceedings are currently suspended for global settlement discussions regarding the wholesale rates payable by our Members. 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 excess 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.

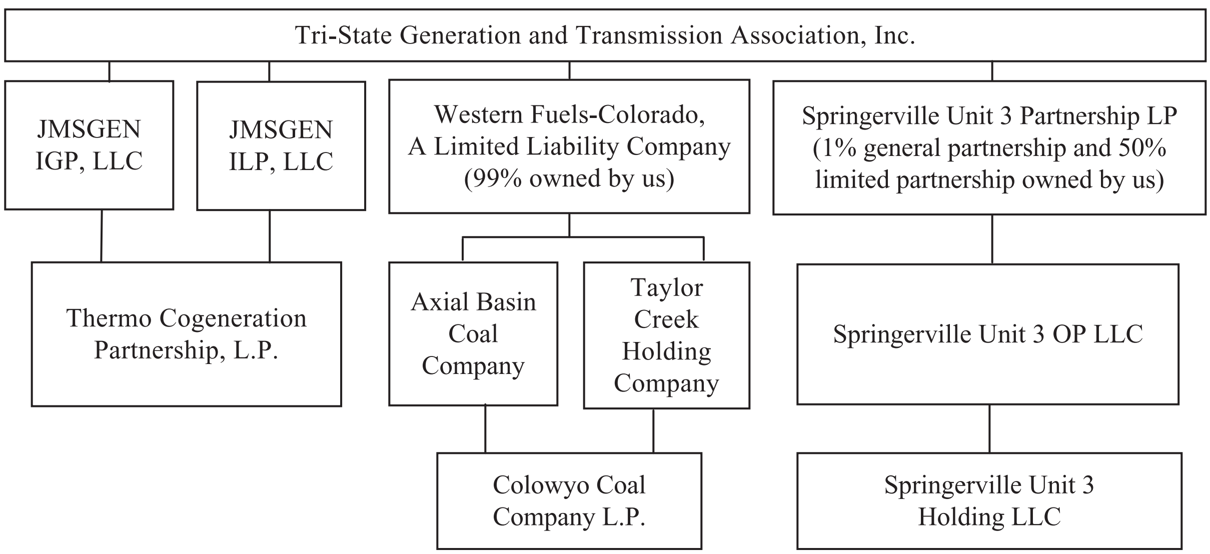
Electric cooperatives generally include distribution cooperatives, such as the majority of our Members, and generation and transmission cooperatives, such as us. The primary purpose of electric distribution cooperatives is to supply the requirements of their retail consumers through bulk purchases of 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 original Members. In 1992, following the reorganization of Colorado-Ute Electric Association, Inc., we acquired certain assets and liabilities of Colorado-Ute Electric Association, Inc. and 10 of its members joined Tri-State. In 2000, Plains Electric Generation and Transmission Cooperative, Inc. merged into Tri-State and increased Tri-State's membership to 44 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 registration statement and is not incorporated herein by reference.

We own or have a majority ownership in the following subsidiaries referenced in this prospectus: Western Fuels-Colorado, A Limited Liability Company, or Western Fuels-Colorado; Colowyo Coal Company L.P., or Colowyo Coal; Thermo Cogeneration Partnership, L.P., or TCP; and Springerville Unit 3 Partnership LP, or Springerville Partnership. Western-Fuels Colorado 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. Western Fuels-Colorado 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 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, including small ditch companies.

The following chart depicts our organization structure:



The Exchange Offer

The Offering of the Old Bonds	We sold the old bonds on October 30, 2014 to Goldman, Sachs & Co. and certain other initial purchasers pursuant to a purchase agreement among us, and Goldman, Sachs & Co., as representative of the initial purchasers, dated October 27, 2014. We refer to Goldman, Sachs & Co. and the other initial purchasers as the "initial purchasers". The initial purchasers subsequently resold the old bonds: (i) to qualified institutional buyers under Rule 144A; and (ii) to persons outside the United States under Regulation S, each as promulgated under the Securities Act of 1933, as amended (the "Securities Act").
Registration Rights Agreement	In connection with the issuance of the old bonds, we entered into a registration rights agreement with Goldman, Sachs & Co., on behalf of itself and the initial purchasers, which obligates us to file a registration statement with the SEC within 180 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 330 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 October 30, 2014 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 , 2015, 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 , 2015 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 3.70% First Mortgage Bonds, Series 2014E-1 due 2024; and $250.0 million aggregate principal amount of 4.70% First Mortgage Bonds, Series 2014E-2 due 2044.
Interest Rate	The new 2014E-1 bonds will bear interest at a rate of 3.70% per annum; and the new 2014E-2 bonds will bear interest at a rate of 4.70% per annum. See "Description of the Bonds—Interest."
Maturity Date	New 2014E-1 bonds: November 1, 2024. New 2014E-2 bonds: November 1, 2044.
Interest Payment Dates	May 1 and November 1.
Master Indenture and Ranking	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." 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." 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."
Optional Redemption	We may redeem the new bonds, in whole or in part, at any time by paying the "make-whole" redemption price plus accrued and unpaid interest, if any, on such bonds, to the redemption date. The new 2014E-1 bonds may be redeemed at par on or after August 1, 2024 (which is the date that is three months prior to the maturity date for the new 2014E-1 bonds), and the new 2014E-2 bonds may be redeemed at par on or after May 1, 2044 (which is the date that is six months prior to the maturity date for the new 2014E-2 bonds). 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	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 14 percent for 2014 and 2015 and 18 percent thereafter. See "Description of the Master Indenture—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations" and "—Equity to Capitalization Ratio Covenant." See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Master Indenture." 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."
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, 2015 and for the three months ended March 31, 2015 and 2014 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, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015 or any future period.

The summary consolidated financial data as of December 31, 2014 and 2013 and for the three years ended December 31, 2014 were derived from our audited consolidated financial statements, included elsewhere in this prospectus. The summary consolidated financial data as of December 31, 2012, 2011 and 2010 and for the two years ended December 31, 2011 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,				
	2015	2014	2014	2013	2012	2011	2010
	(In thousands)						
Selected Income Statement Data:							
Operating revenues	$ 328,391	$ 349,198	$ 1,395,091	$ 1,341,163	$ 1,291,832	$ 1,184,431	$ 1,218,177
Operating expenses	(279,007)	(295,546)	(1,213,214)	(1,152,575)	(1,125,617)	(1,025,676)	(1,037,564)
Operating margins	49,384	53,652	181,877	188,588	166,215	158,755	180,613
Interest expense	(36,163)	(35,742)	(142,357)	(149,463)	(151,905)	(155,022)	(147,649)
Net margins	$ 20,126	$ 24,511	$ 64,236	$ 72,912	$ 52,795	$ 69,934	$ 77,144

	As of March 31,	As of December 31,				
	2015	2014	2013	2012	2011	2010
	(In thousands)					
Balance Sheet Data:						
Total assets	$4,715,784	$4,676,390	$4,701,506	$4,570,552	$4,582,073	$4,269,370
Electric plant, in service, less accumulated depreciation	3,073,153	3,064,063	2,941,860	2,926,700	2,819,499	2,696,137
Construction work in progress	230,771	206,097	231,374	152,355	183,178	201,011
Long-term debt	3,144,148	3,165,960	3,078,140	3,058,353	3,103,252	2,966,753
Patronage capital equity	928,795	908,669	865,379	802,467	759,672	709,738
Accumulated other comprehensive income (loss)	(835)	(828)	3,335	3,415	3,663	4,069
Noncontrolling interest	109,122	109,302	110,740	113,027	116,120	119,983
Total capitalization	$4,181,230	$4,183,103	$4,057,594	$3,977,262	$3,982,707	$3,800,543

	Three Months Ended March 31,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
Other Data:							
MWhs sold							
—Member	3,783,686	3,714,476	15,426,603	15,313,487	15,717,468	15,421,227	15,026,510
—Non-Member	591,324	998,210	3,272,140	3,316,487	3,010,314	3,976,884	3,836,646
Ratio of Earnings to Fixed Charges	1.45	1.53	1.32	1.37	1.22	1.33	1.40

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

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

As of March 31, 2015, we had total debt outstanding of approximately \$3.2 billion, of which approximately \$2.7 billion was secured under our Master Indenture. We have incurred indebtedness primarily to acquire 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 2019. 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. In the years 2015 through 2019, we estimate that we may invest approximately \$1.9 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. In the years 2020 through 2022, we estimate that we will 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 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 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, and we expect that we will spend an additional $352 million through 2019 in efforts to maintain compliance. Currently, our existing coal-fired electric generating facilities generate approximately 62 percent of our overall electricity generation. 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 2014, the EPA proposed emission limits and emission guidelines of carbon dioxide for existing generating facilities in a comprehensive proposed rule referred to as the "Clean Power Plan." 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 proposal. The magnitude of the impact on our existing generating facilities is yet to be determined and will depend on the ultimate deployment of the EPA's final rule and implementation by each of the states in which we have affected assets. The EPA is planning to finalize the rules by 2015 and have state regulations in place in 2017 or 2018. The proposal establishes an implementation date of 2020 and a compliance date of 2030. Emissions of carbon dioxide from our plants totaled approximately 14.1 million short tons in 2014. The outcome of the EPA's rule-making process and any subsequent challenges cannot be determined at this time; however, the Clean Power Plan could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables), 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 increasingly prevalent.

There can be no assurance that we will always be in compliance with all current and future 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 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 of Directors, which is comprised of one representative from each of our 44 Members. In November 2012, three of our New Mexico Members filed protests with the NMPRC of the rate that we filed with the NMPRC in October 2012. 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. The temporary rate rider became effective on October 2, 2014. In March 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the COPUC alleging that our A-37 rate design was unjust and unreasonable. In 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 to allow the parties time to proceed with more extensive discussions on a global settlement. In February 2015, Delta Montrose Electric Association, or DMEA, one of our Colorado Members, filed a petition with the United States Federal Energy Regulatory Commission, or FERC, seeking a declaratory order from FERC finding that its wholesale electric service contract with us is subject to FERC jurisdiction because we have paid off all of our RUS debt. See "Legal Proceedings."

These proceedings or future Member challenges to the rates approved by our Board of Directors 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 outcomes of the rate proceedings in New Mexico and Colorado, or whether a global settlement will be reached, are 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."

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. In the years 2015 through 2019, we estimate that we may invest approximately $1.9 billion in new facilities and upgrades to our existing facilities which will require us to take on significant additional long-term debt. Additionally, we do not currently intend to use RUS as a source of capital going forward, which will cause us to increase our reliance on the capital markets and could raise our borrowing costs.

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;
- 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, 2015, we had $322 million in variable rate debt. The interest rates on this debt could go up. The interest rates could also go up if a third-party associated with the debt, such as a remarketing agent or liquidity provider, displayed financial problems.

Our Members have a substantial amount of industrial and large commercial customers.

Based on 2014 data, industrial and large commercial customers account for approximately 38 percent of our Members' energy sales. A large portion 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 portion of which are in energy production, extraction and transportation, total approximately 20 percent of the aggregate retail electric energy sales of our Members. A significant downturn in the economy 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 Members may fail to satisfy their obligations to us.

We depend on revenues primarily from electric sales to our Members, which comprised approximately 85 percent of our revenues from electric sales in 2014. 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 at one or more Members or because of intentional actions by our Members. Our results of operations and financial condition could be adversely affected if a significant portion of our Members default on their obligations to 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 taken steps to manage this exposure by acquiring coal mines and entering into fixed price or cost-based contracts for some of our coal requirements, including our 2011 acquisition of Colowyo Coal Company L.P., or Colowyo Coal, owner of the Colowyo Mine, with the expectation that the Colowyo Mine will supply coal for Craig Generating Station for our use. We also actively monitor our natural gas requirements and natural gas markets, and in the past we have entered into advance purchase contracts and we may enter into swap arrangements to manage our exposure to fluctuations in the price of natural gas. 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 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's, or NERC, reliability standards addressing the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system. We also intend to comply with existing cybersecurity reliability standards and new statutory and regulatory requirements governing cybersecurity to the extent that they apply to us.

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

Our business model is to provide our Members with a reliable, cost-based supply of electricity. Significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may 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 self-generating customers to receive bill credits for surplus power, could put upward price pressure on our remaining customers because self-generating customers do not currently pay a share of the costs necessary to operate our transmission system. 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 generating facilities, our financial condition and results of operations could be adversely affected

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.

We forecast that our load will grow at an average rate of 3.5 percent annually over the next five years. 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. As of March 31, 2015, our construction work in progress was approximately $231 million.

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 across our system. For example, there are limitations on our ability to move electric energy from Springerville Unit 3, which is operated by Tucson Electric Power Company, to our loads in Colorado. We manage these constraints using economic generator dispatch and alternative generation scheduling practices to relieve the constraints or to acquire energy on the load side of the constraints. The long-term solution for eliminating constraints is construction of additional transmission lines which will 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.

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, we provide energy from renewable sources to meet our Members' obligations under the RPS requirements, and we expect to be able to continue meeting each Member's RPS obligations through 2020, except with respect to any Member that exercises its rights under its wholesale electric service contract to meet part of its obligation with generation owned or controlled by such Member (provided it does not exceed 5 percent of such Member's total load). Neither we nor our Members are subject to an RPS in any other state.

We have executed approximately 370 MW of wind-based power purchase agreements and 30 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 2014, purchased power provided 38 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 the 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 15.7 percent and 15.2 percent, respectively, of our Member sales in 2014. 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 national 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, 2015. 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, 2015
	(In thousands)
First Mortgage Bonds, Series 2014E-1, to be exchanged hereby(1)	$ 249,899
First Mortgage Bonds, Series 2014E-2, to be exchanged hereby(1)	248,693
First Mortgage Obligations, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000
First Mortgage Obligations, Series 2014B, Tranche 2, 4.30%, due through 2039	20,000
First Mortgage Obligations, Series 2014B, Tranche 3, 4.45%, due through 2045	550,000
2.63% CoBank due through 2023	59,959
4.06% CoBank due through 2028	68,345
6.17% CoBank due through 2036	60,943
4.38% CoBank due through 2042	96,136
Variable rate CoBank due through 2044	102,220
6.55% to 8.08% CFC due through 2022	23,645
3.66% CFC due through 2028	68,300
Variable rate CFC due through 2049	102,896
First Mortgage Bonds, Series 2010A, 6.00% due 2040(1)	499,322
First Mortgage Obligations, Series 2009C, Tranche 1, 6.00%, due through 2019	135,714
First Mortgage Obligations, Series 2009C, Tranche 2, 6.31%, due through 2021	110,000
Variable rate 2011 Credit Agreement	70,000
Pollution control revenue bonds, 5.0%, due through 2017(1)	16,114
Variable rate pollution control revenue bonds, due 2036	46,800
Springerville certificates, Series A, 6.04%, due through 2018(1)	91,548
Springerville certificates, Series B, 7.14%, due through 2033(1)	421,133
Colowyo Bonds, 10.19%, due through 2016(1)(2)	16,921
Other	2,523
Total Debt	**$3,241,111**
Less current maturities of long-term debt	(96,963)
Total Long-term Indebtedness	**$3,144,148**
Total Patronage Capital Equity	**928,795**
Accumulated Other Comprehensive Income (Loss)	**(835)**
Noncontrolling Interest	**$ 109,122**
Total Capitalization	**$4,181,230**

(1) Amount shown is net of premium and/or discount.

(2) Debt has been economically defeased.

Selected Historical Financial Data

The following tables set forth selected historical financial data as of and for the periods indicated. The selected consolidated financial data as of March 31, 2015 and for the three months ended March 31, 2015 and 2014 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 operations for these periods. The financial data presented for the three months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ended December 31, 2015 or any future period.

The selected historical financial data as of December 31, 2014 and 2013 and for the three years ended December 31, 2014 were derived from our audited consolidated financial statements, included elsewhere in this prospectus. The selected historical financial data as of December 31, 2012, 2011 and 2010 and for the two years ended December 31, 2011 were derived from the audited financial statements not included in this prospectus. This selected historical 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, as well as the section of this prospectus entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Three Months Ended March 31,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
			(In thousands)				
Income Statement Data:							
Operating revenue:							
Member electric sales	$267,539	$264,594	$1,101,471	$1,091,103	$1,067,085	$1,007,993	$ 981,126
Non-member electric sales	35,063	59,461	197,497	172,102	162,694	152,806	208,357
Other	25,789	25,143	96,123	77,958	62,053	23,632	28,694
	328,391	349,198	1,395,091	1,341,163	1,291,832	1,184,431	1,218,177
Operating expenses							
Purchased power	73,137	78,929	327,445	322,059	310,293	273,287	263,806
Fuel	61,275	73,916	293,033	287,647	273,169	265,917	258,767
Production	53,520	53,013	229,933	209,816	213,674	187,981	206,162
Transmission	37,099	35,754	145,396	138,684	136,853	136,825	121,786
General and administrative	6,151	6,197	28,591	24,325	22,810	18,930	18,694
Depreciation and amortization	34,978	30,897	128,712	121,818	124,861	105,793	131,739
Coal mining	8,827	12,484	40,849	29,889	25,027	2,562	—
Other	4,020	4,356	19,255	18,337	18,930	34,381	36,610
	279,007	295,546	1,213,214	1,152,575	1,125,617	1,025,676	1,037,564
Operating margins	**49,384**	**53,652**	**181,877**	**188,588**	**166,215**	**158,755**	**180,613**
Other income							
Interest Income	1,083	3,261	11,076	17,288	24,035	27,076	20,932
Capital credits from cooperatives	4,294	1,670	8,684	10,922	7,845	7,167	6,162
Other income	1,348	1,269	3,573	3,344	3,563	28,135	2,609
	6,725	6,200	23,333	31,554	35,443	62,378	29,703
Interest expense, net of amounts capitalized	**36,163**	**35,742**	**142,357**	**149,463**	**151,905**	**155,022**	**147,649**
Income taxes	—	—	—	—	—	10	9,738
Net margins including noncontrolling interest	19,946	24,110	62,853	70,679	49,753	66,121	72,405
Net loss attributable to noncontrolling interest	180	401	1,383	2,233	3,042	3,813	4,739
Net margins attributable to the Association	**$ 20,126**	**$ 24,511**	**$ 64,236**	**$ 72,912**	**$ 52,795**	**$ 69,934**	**$ 77,144**

	As of March 31,	As of December 31,				
	2015	2014	2013	2012	2011	2010
			(In thousands)			
Balance Sheet Data:						
Total assets	$4,715,784	$4,676,390	$4,701,506	$4,570,552	$4,582,073	$4,269,370
Electric plant, in service, less accumulated depreciation	3,073,153	3,064,063	2,941,860	2,926,700	2,819,499	2,696,137
Construction work in progress	230,771	206,097	231,374	152,355	183,178	201,011
Long-term debt	3,144,148	3,165,960	3,078,140	3,058,353	3,103,252	2,966,753
Patronage capital equity	928,795	908,669	865,379	802,467	759,672	709,738
Accumulated other comprehensive income (loss)	(835)	(828)	3,335	3,415	3,663	4,069
Noncontrolling interest	109,122	109,302	110,740	113,027	116,120	119,983
Total capitalization	$4,181,230	$4,183,103	$4,057,594	$3,977,262	$3,982,707	$3,800,543

	Three Months Ended March 31,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
Other Data:							
MWhs sold							
—Member	3,783,686	3,714,476	15,426,603	15,313,487	15,717,468	15,421,227	15,026,510
—Non-Member	591,324	998,210	3,272,140	3,316,487	3,010,314	3,976,884	3,836,646
Ratio of Earnings to Fixed Charges	1.45	1.53	1.32	1.37	1.22	1.33	1.40

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 2014, our Members served approximately 614,000 retail electric meters over a 200,000 square-mile area with a population of approximately 1.5 million people. In 2014, we sold 18.7 million MWhs, of which 83 percent was to Members. Total revenue from electric sales was $1.3 billion for 2014, of which 85 percent was from Member sales. For the three months ended March 31, 2015, we sold 4.4 million MWhs, of which 86 percent was to Members. Total revenue from electric sales was $302.6 million for the three months ended March 31, 2015, of which 88 percent was from Member sales.

We were incorporated in 1952 by 24 Member cooperatives and public power districts. We are owned entirely by our Members. In 1992, following the reorganization of Colorado-Ute Electric Association, Inc., we acquired certain assets and liabilities of Colorado-Ute Electric Association, Inc. and 10 of its members joined as Members of our cooperative. In 2000, Plains Electric Generation and Transmission Cooperative, Inc. merged into us and we increased our membership to 44 Members.

We have entered into substantially similar contracts with each Member extending through 2050 for 42 Members (which constitute approximately 94 percent of our revenue from Member sales in 2014) and extending through 2040 for the remaining two Members (Kit Carson Electric Cooperative, Inc. and DMEA, which constitute approximately 6 percent of our revenue from Member sales in 2014), 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, 2015, 16 Members have enrolled in this program with capacity totaling approximately 68 MWs.

We provide electric power to our Members at rates established by our Board of Directors. 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, similar to net income for a corporation. 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 of Directors deems it appropriate to do so. The Master Indenture restricts our ability to retire patronage capital during an Event of Default (as defined in the Master Indenture). We must also satisfy the required ECR after giving effect to such retirement. Additionally, the Board of Directors evaluates liquidity goals and equity goals (that are a part of the Financial Goals and Capital Credits Policy) in determining the timing and amount of patronage capital retirement, and if the Board of Directors 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 for the Board of Directors' discretion on order of retirement. As of March 31, 2015, patronage capital equity is $928.8 million. To date, we have retired approximately $303 million of patronage capital to our Members.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating facilities, long-term purchase contracts, and forward, short-term and spot market energy purchases. We own, lease, have undivided percentage interests in, or have tolling arrangements with respect to, various generating facilities. Additionally, we transmit power to our Members through resources that we own, lease or have undivided percentage interests in, or by wheeling power across lines owned by other transmission providers. We have ownership or capacity interests in approximately 5,400 miles of high-voltage transmission lines and own approximately 225 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. 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.

Summary of Significant Accounting Policies

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.

Basis of Consolidation. Our consolidated financial statements include the accounts of Tri-State, our wholly-owned and majority-owned subsidiaries and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. 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 GAAP, as applied to regulated enterprises.

Jointly Owned Facilities. We own undivided interests in three jointly owned generation facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us), the Missouri Basin Power Project (operated by 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 are 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 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 (have a 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.

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, 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 of Directors 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 of Directors 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.

Use of Estimates. The preparation of our 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 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. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated.

Coal Reserves and Depletion. Coal reserves are recorded at cost. Depletion of coal reserves is computed using the units-of-production method utilizing only proven and probable reserves.

Leases. The accounting for lease transactions in conformity with GAAP requires management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life, in order to determine whether a lease should be classified as operating or capital. We are the lessor under power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey the right to use our power generating equipment for a stated period of time. The lease revenues from these arrangements are included in other operating revenue on 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.

Investments in Other Associations. Investments in other associations include our investment in the patronage capital of other cooperatives and these investments are accounted for using the cost method. 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 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, 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.

Restricted Cash and Investments. Restricted cash and investments represent funds designated by our Board of Directors for specific uses and funds restricted by contract or other legal reasons. A portion of the funds is for payment of debt within one year and is therefore a current asset on our consolidated statements of financial position. The other funds are non-current and are included in other assets and investments.

Fair Value. Accounting guidance defines fair value 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 measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value. 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 are 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.

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.

Patronage Capital. Our net margins are treated as advances of capital by our Members and are allocated to the 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 of Directors deems it appropriate to do so, subject to debt instrument restrictions. Distributions of patronage capital retirements are typically made near year-end, and may be paid either in December or the following January at the option of each of the Members.

Electric Sales Revenue. Revenue from electric energy deliveries is recognized when delivered.

Accounts Receivable—Members and Other. Receivables are primarily related to electric sales to Members and electric sales and other transactions with electric utilities. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible.

Other Operating Revenue. Other operating revenue consists primarily of wheeling revenue, lease revenue, coal sales and revenue from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. The lease revenue is primarily from certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to others the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project. The associated Colowyo Mine expenses are included in coal mine operating expense, depreciation 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.

New Accounting Pronouncements. In April 2015, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, 2015-03, *Interest—Imputation of Interest (Subtopic 835-30), Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt consistent with debt discounts. The recognition and measurement for debt issuance costs are not affected by the amendments in this ASU.

For public business entities, ASU 2015-03 is effective for fiscal years beginning December 15, 2015, and interim periods within those fiscal years. Early adoption is allowed for all entities for financial statements that have not been previously issued. We are currently considering the impact of this amendment on our consolidated financial position and operating results.

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. For public business entities, ASU 2015-02 is effective for the fiscal years, and for interim periods within those fiscal years, beginning 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 are currently considering the impact of this amendment on our consolidated financial position and operating results.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. This amendment replaces current revenue guidance, based on risks and rewards, with a transfer of control model. The core principle under this new model states that revenue should be recognized to depict the transfer of promised 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, ASU 2014-09 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. ASU 2014-09 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. ASU 2014-09 is effective for the fiscal year beginning January 1, 2017 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). Early adoption is not permitted. On April 1, 2015, the FASB proposed deferring the effective date by one year. Under the proposal the standard would be effective for annual reporting periods beginning after December 15, 2017. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. We are currently evaluating the impact of this amendment on our financial position and results of operations.

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 Financial Goals and Capital Credits Policy, approved and subject to change by our Board of Directors, 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 the Master Indenture. On a periodic basis, our Board of Directors will determine whether to retire any patronage capital, and in what amounts, to our Members. To date, we have retired approximately $303 million of patronage capital to our Members.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and a demand rate. Over the past five years, rates to our Members have increased at an average of 2.2 percent per year. Member rates for energy and demand are set by our Board of Directors, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through the transmission and distribution system to customers. Prior to 2013, the energy rate was billed based upon a price per kWh of energy delivered. Demand was billed based upon our Member's highest thirty-minute integrated total demand measured using actual metered kilowatt usage in each monthly billing period during our summer peak period or the winter peak period. Beginning January 1, 2013, we implemented a new rate design (A-37 rate) that incorporates a seasonal average demand rate, which is calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The new rate design also has a new energy rate that incorporates an on-peak/off-peak factor. The new rate schedule is then adjusted for demand response and energy shaping product incentives for Members utilizing those products. In November 2014, we implemented an optional rate available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015, with the energy rate billed based upon a price per kWh of energy delivered and the demand billed 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. As of March 31, 2015, three Members have elected this optional rate.

Although rates established by our Board of Directors are generally not subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rates to the NMPRC. We are also involved in proceedings pending in New Mexico and Colorado regarding efforts by the NMPRC and the COPUC related to our 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 new 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 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. 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. In June 2013, we attempted to withdraw the 2013 wholesale rate notice in New Mexico because our development and implementation of a new 2014 rate would likely be complete prior to NMPRC action on the suspended 2013 rate. The NMPRC suspended consideration of the 2013 rate but did not permit the withdrawal of the rate. On September 10, 2013, we gave notice, as required by New Mexico law, to the NMPRC of our new wholesale rate which was scheduled to become effective on January 1, 2014, which we refer to as the A-38 rate. Four Members filed protests with the NMPRC challenging the 2014 rate. The A-38 rate modified the rate design but did not increase the general revenue requirement. On December 11, 2013, the NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In August 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015 (unless terminated earlier as provided in the preliminary mediation agreement) and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider is 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 2013 and 2014, the overall impact of the New Mexico Members paying a lower rate was approximately $15.6 million and $16.4 million, respectively. For the three months ended March 31, 2015, the overall impact of the New Mexico Members paying a lower rate was approximately $1.9 million.

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

Master Indenture

As of March 31, 2015, we had approximately $2.7 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. The Master Indenture requires us to establish rates annually that are designed to maintain 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. The 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. As of December 31, 2014, our ECR was 25.2 percent and our DSR for the twelve months ended December 31, 2014 was 1.34.

Tax Status

We are a taxable cooperative subject to federal and state taxation. As a taxable cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. Accordingly, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues.

Results of Operations

General

Prior to 2013, we billed our Members for energy and demand based on recovering approximately 42 percent of the total Member revenue requirement from the energy rate component and approximately 58 percent of the total Member revenue requirement from the demand rate component. These levels approximated the percentage of our costs that were energy related and demand related, respectively. Beginning January 1, 2013, we implemented a new rate design (A-37 rate) that incorporates a seasonal average demand rate, which is calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The new rate design also has a new energy rate that incorporates an on-peak/off-peak factor. The new rate schedule is then adjusted for demand response and energy shaping product incentives for Members utilizing those products. In November 2014, we implemented an optional rate available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015, with the energy rate billed based upon a price per kWh of energy delivered and the demand billed 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. As of March 31, 2015, three Members have elected this optional rate. 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 or lower 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.

We currently anticipate that continued growth in our Members' energy requirements will occur. Much of this growth is related to the large commercial sector, due to increased natural gas, crude oil, coal-bed methane and carbon dioxide extraction, processing and transportation. We forecast that our Member load will grow at an average of 3.5 percent annually over the next five years.

Three months ended March 31, 2015 compared to three months ended March 31, 2014

Operating Revenues

Member electric sales increased 69,210 MWhs, or 1.9 percent, to 3,783,686 MWhs for the three months ended March 31, 2015 compared to 3,714,476 MWhs for the same period in 2014. The increase in MWhs sold in 2015 resulted in an increase of $2.9 million, or 1.1 percent, in Member electric sales revenue to $267.5 million for the three months ended March 31, 2015 compared to $264.6 million for the same period in 2014. One of the largest contributors to the increase in revenue was a $7.3 million increase in Member electric sales resulting from one of our Members adding oil and gas loads beginning in mid-2014 (a gas plant was added in May 2014 which had subsequent large increases as two other gas compressor units started later in 2014). Also, one of our Members began serving the City of Gallup, NM starting June 2014, resulting in a $2.1 million increase in Member electric sales revenue for the three months ended March 31, 2015. These increases were partially offset by a $1.4 million decrease in Member electric sales revenue from a Member that serves a large gas pipeline compressor load with irregular operations.

Non-member electric sales decreased 406,886 MWhs, or 40.8 percent, to 591,324 MWhs for the three months ended March 31, 2015 compared to 998,210 MWhs for the same period in 2014. Non-member electric sales revenue decreased $24.4 million, or 41.0 percent, to $35.1 million for the three months ended March 31, 2015 compared to $59.5 million for the same period in 2014. The decrease in non-member electric sales revenue was largely due to an $11.6 million decrease in long-term firm energy sales to non-members and an $8.0 million decrease in short-term market sales. The decrease in long-term firm energy sales to non-members was due to the termination of several power sale agreements on February 1, 2015 and September 30, 2014 that were not renewed, resulting in a decrease of 238,609 MWhs sold for the three months ended March 31, 2015 compared to the same period in 2014. The decrease in short-term market sales was due to lower market prices and a 196,474 MWh decrease in MWhs sold for the three months ended March 31, 2015 compared to the same period in 2014 resulting from lower generation from our coal-fired plants. Additionally, there was a $5.0 million decrease in non-member electric sales revenue due to the recognition in the three-months ended March 31, 2014 of $5.0 million of regulatory liabilities previously recorded for deferred non-member electric sales revenue and there being no such recognition in the three-months ended March 31, 2015. The recognition in 2014 resulted in reduced Member revenue requirements (lower Member rates) as was required in 2014 by the Board of Directors in accordance with its budgetary and rate-setting authority.

Operating Expenses

Purchased power increased 14,519 MWhs, or 0.9 percent, to 1,642,951 MWhs for the three months ended March 31, 2015 compared to 1,628,432 MWhs for the same period in 2014. The increase in MWhs purchased in 2015 was due to increased Member load demand and lower generation from our coal-fired plants resulting from an increase in scheduled and unscheduled outages. Despite the increase in MWhs purchased, purchased power expense decreased $5.8 million, or 7.3 percent, to $73.1 million for the three months ended March 31, 2015 compared to $78.9 million for the same period in 2014 as a result of a 3.5 percent decrease in the average price due to lower market prices.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense decreased $12.6 million, or 17.1 percent, to $61.3 million for the three months ended March 31, 2015 compared to $73.9 million for the same period in 2014. The decrease in expense was primarily due to lower coal expense because of an 11.7 percent decrease in generation at our coal burning generating stations resulting from an increase in scheduled and unscheduled outages, primarily at our Craig, Escalante and Springerville Generating Stations.

Coal mining expense includes the Colowyo Mine operating expenses related to the portion of the coal sold from the Colowyo Mine pursuant to a contract expiring in 2017 to other joint owners in the Yampa Project. Coal mining expense decreased $3.7 million, or 29.3 percent, to $8.8 million for the three months ended March 31, 2015 compared to $12.5 million for the same period in 2014. The decrease in expense was due to lower coal mine operating expenses related to delivering less coal to the other joint owners in the Yampa Project.

Other Income

Interest income decreased $2.2 million, or 66.8 percent, to $1.1 million for the three months ended March 31, 2015 compared to $3.3 million for the same period in 2014. The decrease in interest income consisted primarily of our reduced investment in the RUS cushion of credit, which comprised $1.7 million of the decrease. Additionally, there was a decrease of $310,000 related to interest earned on our investment of National Rural Utilities Cooperative Finance Corporation, or CFC, capital term certificates. CFC is a member-owned, nonprofit cooperative and is a lender for electric cooperatives. Capital term certificates represent our membership in CFC. As of March 31, 2015, our capital term certificates investment was $16.5 million compared to $30.2 million as of March 31, 2014, and is included in investments in other associations.

Capital credits from cooperatives consist of patronage capital allocations received from other cooperatives of which we are a member, including cooperative banks, electric suppliers and service companies. Capital credits increased $2.6 million, or 157.1 percent, to $4.3 million for the three months ended March 31, 2015 compared to $1.7 million for the same period in 2014. The increase in capital credits was primarily due to a higher allocation of $1.8 million from Trapper Mining. Our membership interest in Trapper Mining was $14.8 million as of March 31, 2015, and is included in investments in and advances to coal mines. The increase in capital credits from cooperatives was also due to a higher patronage allocation of $450,000 from CoBank, ACB, or CoBank. CoBank is a cooperatively organized financial services institution capitalized primarily by eligible borrowers, who earn equity (patronage allocation) over time commensurate with the amount of business they do with the organization. Our investment in CoBank was $6.2 million as of March 31, 2015 (included in investments in other associations), and total outstanding debt owed by us to CoBank was $387.6 million as of March 31, 2015.

Year ended December 31, 2014 compared to years ended December 31, 2013 and 2012

Operating Revenues

Member electric sales increased 113,116 MWhs, or 0.7 percent, to 15,426,603 MWhs in 2014 compared to 2013, and decreased 403,981 MWhs, or 2.6 percent, to 15,313,487 MWhs in 2013 compared to 2012. The increase in MWhs sold in 2014 resulted in an increase of $10.4 million in Member electric sales revenue to $1.1 billion in 2014 compared to 2013. Despite the decrease in MWhs sold in 2013, Member electric sales revenue increased $24.0 million, or 2.3 percent, to $1.1 billion in 2013 compared to 2012 due to a 4.9 percent Member rate increase effective January 1, 2013.

Non-member electric sales decreased 44,347 MWhs, or 1.3 percent, to 3,272,140 MWhs in 2014 compared to 2013, and increased 306,173 MWhs, or 10.2 percent, to 3,316,487 MWhs in 2013 compared to 2012. 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 primarily 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 the Board of Directors in accordance with its budgetary and rate-setting authority. The increase in non-member electric sale 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. The increase in MWhs for 2013 was primarily due to increased firm contractual sales by Springerville Unit 3 after having reduced sales in 2012 as a result of a three-month outage to repair a damaged turbine. The increase in MWhs resulted in non-member electric sales revenue increasing $9.4 million, or 5.8 percent, to $172.1 million in 2013 compared to 2012.

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 $18.2 million, or 23.3 percent, to $96.1 million in 2014 compared to 2013, and increased $15.9 million, or 25.6 percent, to $78.0 million in 2013 compared to 2012. 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. The increase in other operating revenue in 2013 was primarily due to increased lease revenues of $12.6 million resulting from the resumption of gas tolling arrangements at the Knutson and Limon Generating Stations on May 1, 2013.

Operating Expenses

Purchased power increased 325,287 MWhs, or 4.8 percent, to 7,156,528 MWhs in 2014 compared to 2013, and decreased 562,054 MWhs, or 7.6 percent, to 6,831,241 MWhs in 2013 compared to 2012. Purchased power expense increased $5.4 million, or 1.7 percent, to $327.4 million in 2014 compared to 2013, and increased $11.8 million, or 3.8 percent, to $322.1 million in 2013 compared to 2012. The increase in expense in 2014 was due to the increase in MWhs purchased, partially offset by lower market prices for electricity. The increase in purchased power expense in 2013 was due to a 10.7 percent increase in the average price of purchased power resulting from higher 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 2013, and increased $14.5 million, or 5.3 percent, to $287.7 million in 2013 compared to 2012. 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. The increase in expense for 2013 was due to higher coal expense resulting from increased generation at our coal burning generating stations primarily due to the increased MWhs generated at Springerville Unit 3, partially offset by lower natural gas expense resulting from a decrease 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 2013, and decreased $3.9 million, or 1.8 percent, to $209.8 million in 2013 compared to 2012. 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 Station Unit 2 for boiler repairs and a turbine overhaul. The decrease in expense for 2013 was primarily due to the reduction in scheduled and unscheduled maintenance outages at coal-fired generating stations offset by higher production costs resulting from increased generation at coal-fired generating stations, primarily the Craig, Laramie River and Springerville Unit 3 generating stations.

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 2013, and increased $1.8 million, or 1.3 percent, to $138.7 million in 2013 compared to 2012. These increases were 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 $11.0 million, or 36.7 percent, to $40.8 million in 2014 compared to 2013, and increased $4.9 million, or 19.4 percent, to $29.9 million in 2013 compared to 2012. The increases in expense for 2014 and 2013 were 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 2013, and decreased $6.7 million, or 28.1 percent, to $17.3 million in 2013 compared to 2012. The decreases in interest income were due to the declining investment in the RUS cushion of credit, which earned a 5 percent return. The investment in the RUS cushion of credit was eliminated by the 2014 debt refinancing when the RUS debt and Federal Financing Bank, or FFB, debt was entirely paid off.

Interest Expense

Interest expense, net of amounts capitalized, includes the amount of interest on outstanding long-term debt less the interest charged during construction. Interest expense decreased $7.1 million, or 4.8 percent, to $142.4 million in 2014 compared to 2013, and decreased $2.4 million, or 1.6 percent, to $149.5 million in 2013 compared to 2012. The decreases in interest expense were primarily due to lower average interest rates on principal balances.

Financial Condition

March 31, 2015 compared to December 31, 2014

Assets

Construction work in progress increased $24.7 million, or 12.0 percent, to $230.8 million as of March 31, 2015 compared to $206.1 million as of December 31, 2014. The increase was primarily due to capital expenditures related to various generation and transmission capital improvements and system upgrades.

Cash and cash equivalents decreased $15.3 million, or 16.6 percent, to $77.2 million as of March 31, 2015 compared to $92.5 million as of December 31, 2014. The decrease was primarily due to higher capital expenditures ($69.8 million for the three months ended March 31, 2015 compared to $37.0 million for the same period in 2014) for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements, debt payments of $58.3 million (primarily $34.8 million for the Springerville certificates and $20 million for the secured revolving credit facility with Bank of America N.A. and CoBank as Joint Lead Arrangers in the amount of $750 million, which we refer to as the 2011 Credit Agreement) and a $20 million decrease in our investment in the Basin Electric Member Investment Program (comprised of short-term funds with maturities of less than 90 days). These decreases were partially offset by debt proceeds of $40.0 million from the 2011 Credit Agreement, a $27.6 million increase in accounts payable, accrued expenses and accrued interest due to the timing and payment of these liabilities and a $19.9 million increase in Member accounts receivable (primarily due to the timing of an $8.5 million payment from one of our Members for a transmission project and a $12.3 million decrease in Member accounts receivable due to lower Member electric sales in March 2015 compared to December 2014).

Coal inventory increased $9.5 million, or 23.4 percent, to $50.2 million as of March 31, 2015 compared to $40.7 million as of December 31, 2014. The increase was primarily due to a $5.8 million increase in coal inventory at our Springerville Generating Station and a $2.1 million increase in coal inventory at our Escalante Generating Station. The increase in Springerville coal inventory was due to increased rail deliveries and lower generation resulting from planned outages. The increase in Escalante coal inventory was due to lower generation resulting from decreased load demand and an outage.

Other deferred charges increased $10.9 million, or 6.1 percent, to $189.4 million as of March 31, 2015 compared to $178.5 million as of December 31, 2014. The increase was primarily due to an increase of $6.9 million related to advance payments to the operating agents of jointly owned facilities to fund operations and capital project activities and a $1.9 million increase in expenditures for preliminary surveys, plans and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects (the largest increases of which included $1.2 million in connection with the expansion project of an existing coal-fired generating station called Holcomb Generating Station, which we refer to as Holcomb and $301,000 for a transmission project located in eastern Colorado known as the Eastern Plains Transmission Project).

Equity and Liabilities

Patronage capital equity increased $20.1 million, or 2.2 percent, to $928.8 million as of March 31, 2015 compared to $908.7 million as of December 31, 2014. The increase was due to a margin of $20.1 million for the three months ended March 31, 2015.

Noncontrolling interest represents the 49 percent of equity interests in the Springerville Unit 3 Partnership, LP, or the Springerville Partnership, that is not owned by us. Noncontrolling interest decreased $180,000, or 0.2 percent, to $109.1 million as of March 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 $180,000.

Long-term debt decreased $21.8 million, or 0.7 percent, to $3.144 billion as of March 31, 2015 compared to $3.166 billion as of December 31, 2014, and current maturities of long-term debt increased $2.6 million, or 2.8 percent, to $96.9 million as of March 31, 2015 compared to $94.3 million as of December 31, 2014. The net decrease of $19.2 million was due to debt payments of $58.3 million (primarily $20.0 million for the 2011 Credit Agreement, and $34.8 million for the Springerville certificates) offset by debt proceeds of $40.0 million from the 2011 Credit Agreement.

Accounts payable increased $18.0 million, or 17.5 percent, to $121.2 million as of March 31, 2015 compared to $103.2 million as of December 31, 2014. The increase was primarily due to the timing and payment of trade payables.

Accrued interest increased $15.1 million, or 46.5 percent, to $47.6 million as of March 31, 2015 compared to $32.5 million as of December 31, 2014. The increase was primarily due to the timing and payment of interest related to the First Mortgage Bonds, Series 2010A and the First Mortgage Obligations, Series 2014B.

December 31, 2014 compared to December 31, 2013

Assets

Electric plant in service increased $227.7 million, or 4.6 percent to $5.193 billion as of December 31, 2014 compared to $4.965 billion as of December 31, 2013. The increase was due to the completion of generation and transmission capital improvements and system upgrades to serve the growing needs of our Members.

Cash and cash equivalents decreased $100.6 million, or 52.1 percent, to $92.5 million as of December 31, 2014 compared to $193.1 million as of December 31, 2013. The decrease was primarily due to debt payments of $1.740 billion, debt prepayment transaction costs of $184.1 million related to the 2014 debt refinancing and retirement of patronage capital of $20.6 million, partially offset by debt proceeds of $1.690 billion. Significant debt payments in 2014 included $1.260 billion of RUS and FFB debt, $60.9 million of CFC debt, $12.9 million of grantor trust certificates, $180.0 million of the 2011 Credit Agreement, $32.8 million of the Springerville certificates, $27.1 million of the First Mortgage Obligations, Series 2009C, and $7.1 million of the coal contract receivable collateralized bonds, or Colowyo Bonds. Significant debt proceeds in 2014 included $498.6 million from the First Mortgage Bonds, Series 2014E-1 and E-2, $750.0 million from the First Mortgage Obligations, Series 2014B, $170.6 million from CoBank, $170.5 million from CFC and $100.0 million from the 2011 Credit Agreement.

Restricted cash and investments consist of (1) funds designated by our Board of Directors for specific uses, (2) funds restricted by contract or other legal reasons, (3) investments in securities pledged as collateral in connection with the in-substance defeasance of debt assumed in the 2011 acquisition of Colowyo Coal, and (4) amounts in the cushion of credit program administered by the RUS which are voluntary irrevocable deposits that can only be used to make scheduled payments on loans made or guaranteed by the RUS (we participated in this program until the RUS and FFB debt was paid off in November 2014 and the balance in the RUS cushion of credit program was eliminated). A portion of the restricted funds is for the payment of debt within one year and is therefore a current asset on the statements of financial position. The other restricted funds are noncurrent and are included in other assets and investments. The noncurrent portion of restricted cash and investments was $39.4 million as of December 31, 2014 and $118.1 million as of December 31, 2013, a decrease of $78.7 million. The current portion of restricted cash and investments was $9.8 million as of December 31, 2014 and $125.7 million as of December 31, 2013, a decrease of $115.9 million. The total decrease of $194.6 million was primarily due to restricted funds used for the payment of RUS and FFB debt of $137.7 million and restricted funds used for the payment of Platte County Pollution Control Revenue Bonds of $48.0 million. Additionally, the decrease in restricted cash and investments was due to the maturity of U.S. Treasury Notes of $8.7 million that were pledged as collateral in connection with the in-substance defeasance of principal and interest payments on the Colowyo Bonds.

Regulatory assets increased $177.1 million to $426.0 million as of December 31, 2014 compared to $248.9 million as of December 31, 2013. The increase was due primarily to the payment of transaction costs of $184.1 million in conjunction with the prepayment of long-term debt in 2014. These debt prepayment transaction costs were approved by our Board of Directors to be recorded as regulatory assets and are being amortized into interest expense over the 21.4 year average life of the new debt issued.

Equity and Liabilities

Patronage capital equity increased $43.3 million to $908.7 million as of December 31, 2014 compared to $865.4 million as of December 31, 2013. The increase was due to a 2014 margin of $64.2 million, offset by 2014 patronage capital retirements of $20.9 million.

Noncontrolling interest represents the 49 percent of equity interests in the Springerville Partnership that is not owned by us. Noncontrolling interest decreased $1.4 million to $109.3 million as of December 31, 2014 compared to $110.7 million as of December 31, 2013. The decrease was due to a Springerville Partnership net loss attributable to the noncontrolling interest of $1.4 million.

Long-term debt increased $87.8 million, or 2.9 percent, to $3.166 billion as of December 31, 2014 compared to $3.078 billion as of December 31, 2013, and current maturities of long-term debt decreased $142.2 million, or 60.1 percent, to $94.3 million as of December 31, 2014 compared to $236.6 million as of December 31, 2013. The net decrease of $54.4 million was primarily due to debt proceeds of $100 million from the 2011 Credit Agreement and $1.590 billion related to the 2014 debt refinancing, offset by debt payments of $405.5 million, primarily $180 million for the 2011 Credit Agreement, $48.0 million for the Platte County Pollution Control Revenue Bonds, $27.1 million for the First Mortgage Obligations, Series 2009C and $32.8 million for the Springerville certificates, and debt payments of $1.334 billion related to the 2014 debt refinancing.

Regulatory liabilities decreased $20.0 million, or 30.8 percent, to $45.0 million as of December 31, 2014 compared to $65.0 million as of December 31, 2013. The decrease was due to the recognition of $20.0 million of the regulatory liability related to the previously deferred non-member electric sales revenue in 2014 non-member electric sales.

Liquidity

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

	(In thousands)
Cash and Cash Equivalents	$ 77,150
2011 Credit Agreement Availability	632,258
Total Liquid Funds Available	**$709,408**

The 2011 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, 2015. The 2011 Credit Agreement is secured under the Master Indenture and has a term extending through July 26, 2019. As of March 31, 2015, we have advanced funds of $70 million and issued a letter of credit for the Moffat County, CO Pollution Control Bonds in the principal amount of $46.8 million plus accrued interest. Funds advanced under the 2011 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.

The 2011 Credit Agreement contains financial covenants, including DSR and ECR requirements, in line with the covenants contained in our Master Indenture. A violation of these covenants would result in the inability to borrow under the facility.

Between projected cash on hand and the 2011 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, 2015 compared to March 31, 2014

Operating activities. Net cash provided by operating activities was $87.1 million for the three months ended March 31, 2015 compared to $48.6 million for the same period in 2014, an increase of

$38.5 million, or 79.1 percent. The increase in operating cash was primarily due to an increase in accounts payable, accrued expenses and accrued interest due to the timing and payment of these liabilities and an increase in Member accounts receivable due to the timing of an $8.5 million payment from one of our Members for a transmission project and a decrease in Member accounts receivable due to lower Member electric sales in March 2015 compared to December 2014.

Investing activities. Net cash used in investing activities was $76.3 million for the three months ended March 31, 2015 compared to $40.7 million for the same period in 2014, an increase of $35.6 million, or 87.6 percent. The increase in investing activities 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 net cash used in investing activities was also impacted by a $1.5 million, or 77.9 percent, decrease in the retirement of our investment in CFC capital term certificates. Our total investment in CFC's capital term certificates of $16.5 million include various investments ranging from the 1970's to 2003 and are periodically retired.

Financing activities. Net cash used in financing activities was $26.1 million for the three months ended March 31, 2015 compared to $96.5 million for the same period in 2014, a decrease of $70.4 million, or 72.9 percent. The decrease in financing activities was primarily due to lower debt payments of $58.3 million for the three months ended March 31, 2015 compared to $89.4 million for the same period in 2014 and higher proceeds from issuance of debt of $40.0 million (from the 2011 Credit Agreement) for the three months ended March 31, 2015 compared to $0 for the same period in 2014. Significant debt payments for the three months ended March 31, 2015 included $34.8 million for the Springerville certificates and $20.0 million for the 2011 Credit Agreement, compared to debt payments for the same period in 2014 which included $32.8 million for the Springerville certificates, $30.0 million for the 2011 Credit Agreement and $18.4 million for FFB debt.

December 31, 2014 compared to December 31, 2013

Operating activities. Net cash provided by operating activities increased $35.2 million, or 23.2 percent, to $186.9 million in 2014 compared to $151.7 million in 2013. The increase in operating cash in 2014 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 increased $1.6 million to $214.6 million in 2014 compared to $213.0 million in 2013. The increase was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements. The increase in cash used for capital expenditures was offset by an increase in proceeds from other investments related to the retirement of CFC capital term certificates.

Financing activities. Financing cash flow activity decreased $245.7 million in 2014 compared to 2013. The decrease was primarily due to higher total debt payments in 2014 of $1.740 billion, primarily $180 million for the 2011 Credit Agreement, $48.0 million for the Platte County Pollution Control Revenue Bonds, $27.1 million for the First Mortgage Obligations, Series 2009C and $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 2011 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.

December 31, 2013 compared to December 31, 2012

Operating activities. Net cash provided by operating activities increased $58.9 million, or 63.5 percent, to $151.7 million in 2013 compared to $92.8 million in 2012. The increase in operating cash for 2013 was primarily due to higher net margins, a decrease in accounts receivable and coal inventories and the timing of the payment of accounts payable and accrued expenses, partially offset by a $71.2 million prepayment of our pension costs.

Investing activities. Net cash used in investing activities increased $28.1 million, or 15.2 percent to $213.0 million in 2013 compared to $184.9 million in 2012. The increase was primarily due to higher capital expenditures to expand generation, transmission and telecommunication capabilities.

Financing activities. Financing cash flow activity increased $116.8 million in 2013 compared to 2012. The increase was primarily due to lower debt proceeds of $258.9 million in 2013 compared to $390.2 million in 2012 offset by lower debt payments of $196.5 million in 2013 compared to $416.8 million in 2012.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility costs, market factors and other items affecting our forecasts. In the years 2015 through 2019, we estimate that we may invest approximately $1.9 billion in new facilities and upgrades to our existing facilities.

Our actual capital expenditures for existing and new generating and existing and new transmission facilities going forward depend on a variety of factors, including Member load growth, availability of necessary permits, 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, 2015, we have incurred capital expenditures of approximately $90.5 million in connection with Holcomb, and approximately $70.3 million in connection with a possible generating station in southeastern Colorado, which we refer to as the Colorado Power Project. Additional capital expenditures for Holcomb and the Colorado Power Project are not included in our current capital expenditure projections.

Outstanding Obligations. We have first mortgage obligations and pollution control revenue bonds outstanding which are secured on a parity basis by our Master Indenture (except for the Springerville certificates (which are secured only by a mortgage and lien on Springerville Generating Station Unit 3 and the Springerville lease) and the Colowyo Bonds (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)).

We have outstanding obligations with CFC which amortize through 2022 and accrue interest at rates between 6.55% and 8.08%. We have a small amount of variable rate debt with CFC which amortizes through 2026. We also have a $68 million amortizing note maturing in 2028, which bears interest at a rate of 3.657%, and a $102 million variable rate note which amortizes through 2049.

We have a 2012 term loan agreement with CoBank and certain other farm credit banks under which we issued a secured note in an amount of $100 million which amortizes through 2042 at a rate of 4.38%. We have a 2014 term loan agreement with CoBank and certain other farm credit banks under which we issued a $68 million amortizing note maturing in 2028, which bears interest at a rate of

4.06%, and a $102 million variable rate amortizing note maturing in 2044. We also have a 2013 unsecured term loan agreement with CoBank and certain other farm credit banks under which we issued a $71.0 million unsecured amortizing note maturing in 2023, which bears interest at a rate of 2.63%. We also have a secured amortizing note issued under our CoBank master loan agreement maturing in 2036, which bears interest at a rate of 6.17%.

We have our First Mortgage Obligations, Series 2009C which consist of private placement notes in an aggregate principal amount of $300 million. The private placement included the issuance of $190 million of Tranche 1 Notes at 6.00%, amortizing through 2019 and $110 million of Tranche 2 Notes at 6.31%, amortizing through 2021.

We have our First Mortgage Bonds, Series 2010A which we issued, in an unregistered offering pursuant to Rule 144A under the Securities Act, with an aggregate principal amount of $500 million at 6.00% due 2040.

We have our First Mortgage Obligations, Series 2014B in an aggregate amount of $750 million issued to a group of institutional investors in a private placement pursuant to Section 4(a)(2) of the Securities Act. The Tranche 1 Notes were priced in an aggregate amount of $180 million, bear interest at a rate of 3.90% per annum and amortize through 2033. The Tranche 2 Notes were priced in an aggregate amount of $20 million, bear interest at a rate of 4.30% per annum and amortize through 2039. The Tranche 3 Notes were priced in an aggregate amount of $550 million, bear interest at a rate of 4.45% per annum and amortize through 2045.

We have our First Mortgage Bonds, Series 2014E-1 and E-2, which we issued pursuant to Rule 144A and Regulation S under the Securities Act, with an aggregate principal amount of $500 million. Series 2014E-1 was priced in an aggregate amount of $250 million which matures in 2024 and bears interest at a rate of 3.70% per annum. Series 2014E-2 was priced in an aggregate amount of $250 million which matures in 2044 and bears interest at a rate of 4.70% per annum.

We have the 2011 Credit Agreement with an aggregate commitment of $750 million and expiring in 2019.

We have variable rate pollution control revenue bonds due in 2036 and 5.0% pollution control revenue bonds which amortize through 2017.

We have the Springerville certificates, which include Series A certificates which amortize through 2018 and accrue interest at a rate of 6.04% and Series B certificates which amortize through 2033 and accrue interest at a rate of 7.14%.

We have the Colowyo Bonds which amortize through 2016 and accrue interest at a rate of 10.19%. We have entered into an in-substance defeasance of these bonds.

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, 2014:

	Payments Due by Period				
Obligations	**Total**	**Less Than 1 Year**	**1 - 3 Years**	**4 - 5 Years**	**More Than 5 Years**
			(In thousands)		
Long-term Indebtedness:					
Principal	$3,260,302	$ 94,342	$202,500	$229,441	$2,734,019
Interest(1)	2,758,124	155,293	296,399	277,481	2,028,951
Operating Lease Obligations	28,442	5,359	11,197	11,886	—
Construction Obligations	67,400	56,300	11,100	—	—
Coal Purchase Obligations	665,104	101,266	210,550	208,076	145,212
Total	$6,779,372	$412,560	$731,746	$726,884	$4,908,182

(1) Includes interest expense related to approximately $302 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, 2014.

We expect to fund these obligations with cash flows from operations, borrowings under the 2011 Credit Agreement and the issuance of additional long-term indebtedness.

Indebtedness. As of March 31, 2015, we had approximately $2.7 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 (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, pollution control revenue bonds, and amounts outstanding under the 2011 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 Unit 3 and the Springerville lease.

Operating Lease Obligations. We have a 10-year power purchase agreement with Brush Cogeneration Partners to toll natural gas at the Brush Generating Station for 72 MWs which began on October 1, 2009. We account for this power purchase agreement as an operating lease because it conveys to us the right to use power generating equipment for a stated period of time.

Coal Purchase Obligations. We have commitments to purchase coal for our generating stations under long-term contracts that expire between 2017 and 2034. These contracts require us to purchase a minimum quantity of coal at prices that are subject to escalation clauses that reflect cost increases incurred by the suppliers and market conditions.

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

Rating Triggers

Our current senior secured ratings are "A3 (stable outlook)" by Moody's, "A (negative outlook)" by S&P, and "A (negative outlook)" by Fitch.

The 2011 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 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 Brush Cogeneration Partners to toll natural gas at the Brush Generating Station for 72 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 Long-Term Debt

The fair values of long-term 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 long-term debt are as follows:

	As of March 31, 2015		As of December 31, 2014	
Long-Term Debt	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(In thousands)			
CFC	194,841	195,450	195,884	258,180
First Mortgage Bonds, Series 2014E-1 and E-2	498,592	540,928	498,585	524,293
First Mortgage Bonds, Series 2010A	499,322	663,420	499,322	632,365
First Mortgage Obligations, Series 2014B	750,000	827,352	750,000	784,126
First Mortgage Obligations, Series 2009C	245,714	280,305	245,714	277,061
Pollution Control Revenue Bonds	62,914	62,990	62,955	63,197
2011 Credit Agreement	70,000	69,935	50,000	49,323
CoBank	387,603	404,819	390,018	398,839
Springerville Certificates	512,681	669,928	548,064	709,278
Colowyo Bonds	16,921	17,320	17,224	17,127
Other	2,523	2,745	2,536	2,724
Total	$3,241,111	$3,735,192	$3,260,302	$3,716,513

Commodity Price Risk

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

We have entered into gas tolling arrangements which we expect will provide energy to meet our projected load forecasts through at least 2017, reducing our exposure to fluctuations in energy price markets, and increasing our risk to gas price fluctuations during this period of time. We have also implemented a gas risk management program to manage this 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 72 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 only utilize them as a peaking resource. For the three months ended March 31, 2015, these resources accounted for 2.1 percent of the energy we supplied to our firm load obligations and leases.

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 of Directors is given monthly 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, 2015, we were exposed to the risk of changes in interest rates related to our \$321.9 million of variable rate debt, including \$70.0 million outstanding under the 2011 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, 2015, the weighted average interest rate on this variable rate debt was 1.32 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, 2015, we had 9.9 percent of our total debt in a variable rate mode. An increase in interest rates of 100 basis points would increase our annual debt service by approximately \$3.2 million.

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 supply wholesale electric power to our 44 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 2014, we sold 15.4 million MWhs to our Members and 3.3 million MWhs to non-members. For the three months ended March 31, 2015, we sold 3.8 million MWhs to Members and 591,324 MWhs to non-members. Total revenue from electric sales was $1.3 billion for 2014 and $302.6 million for the three months ended March 31, 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 (residential and business) customers 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.

Including our subsidiaries, as of March 31, 2015 we employed 1,545 people, of which approximately 356 were subject to collective bargaining agreements. As of March 31, 2015, only the collective bargaining agreement for the New Horizon Mine, which expires on January 17, 2016, expires within one year.

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 2,843 MWs, including 1,874 MWs from coal-fired base load facilities and 969 MWs from gas-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 194 MWs from renewable energy resources, including wind, solar and small hydro. 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 5,400 miles of high-voltage transmission lines and own approximately 225 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 "—Purchased Power."

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 excess 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 original Members. In 1992, following the reorganization of Colorado-Ute Electric Association, Inc., we acquired certain assets and liabilities of Colorado-Ute Electric Association, Inc. and 10 of its members joined Tri-State. In 2000, Plains Electric Generation and Transmission Cooperative, Inc. merged into Tri-State and increased Tri-State's membership to 44 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.

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:

Big Horn Rural Electric Company
Basin, Wyoming

Carbon Power & Light, Inc.
Saratoga, Wyoming

Central New Mexico Electric Cooperative, Inc.
Mountainair, New Mexico

Chimney Rock Public Power District
Bayard, Nebraska

Columbus Electric Cooperative, Inc.
Deming, New Mexico

Niobrara Electric Association, Inc.
Lusk, Wyoming

Northern Rio Arriba Electric Cooperative, Inc.
Chama, New Mexico

Northwest Rural Public Power District
Hay Springs, Nebraska

Otero County Electric Cooperative, Inc.
Cloudcroft, New Mexico

Panhandle Rural Electric Membership Association
Alliance, Nebraska

Continental Divide Electric Cooperative, Inc.
Grants, New Mexico

Delta-Montrose Electric Association
Montrose, Colorado

Empire Electric Association, Inc.
Cortez, Colorado

Garland Light & Power Company
Powell, Wyoming

Gunnison County Electric Association, Inc.
Gunnison, Colorado

High Plains Power, Inc.
Riverton, Wyoming

High West Energy, Inc.
Pine Bluffs, Wyoming

Highline Electric Association
Holyoke, Colorado

Jemez Mountains Electric Cooperative, Inc.
Espanola, New Mexico

K.C. Electric Association, Inc.
Hugo, Colorado

Kit Carson Electric Cooperative, Inc.
Taos, New Mexico

La Plata Electric Association, Inc.
Durango, Colorado

The Midwest Electric Cooperative Corporation
Grant, Nebraska

Mora-San Miguel Electric Cooperative, Inc.
Mora, New Mexico

Morgan County Rural Electric Association
Fort Morgan, Colorado

Mountain Parks Electric, Inc.
Granby, Colorado

Mountain View Electric Association, Inc.
Limon, Colorado

Poudre Valley Rural Electric Association, Inc.
Fort Collins, Colorado

Roosevelt Public Power District
Scottsbluff, Nebraska

San Isabel Electric Association, Inc.
Pueblo West, Colorado

San Luis Valley Rural Electric Cooperative, Inc.
Monte Vista, Colorado

San Miguel Power Association, Inc.
Nucla, Colorado

Sangre De Cristo Electric Association, Inc.
Buena Vista, Colorado

Sierra Electric Cooperative, Inc.
Elephant Butte, New Mexico

Socorro Electric Cooperative, Inc.
Socorro, New Mexico

Southeast Colorado Power Association
La Junta, Colorado

Southwestern Electric Cooperative, Inc.
Clayton, New Mexico

Springer Electric Cooperative, Inc.
Springer, New Mexico

United Power, Inc.
Brighton, Colorado

Wheat Belt Public Power District
Sidney, Nebraska

Wheatland Rural Electric Association, Inc.
Wheatland, Wyoming

White River Electric Association, Inc.
Meeker, Colorado

Wyrulec Company
Torrington, Wyoming

Y-W Electric Association, Inc.
Akron, Colorado

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 94 percent of our revenue from Member sales in 2014) and extending through 2040 for the remaining two Members (Kit Carson Electric Cooperative, Inc. and DMEA which constitute approximately 6 percent of our revenue from Member sales in 2014), 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, 2015, 16 Members have enrolled in this program with capacity totaling approximately 68 MWs.

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 of Directors. 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 of Directors 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 "—Rates and 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 11.26 percent of our Member revenue in 2014. No other Member exceeded 10 percent of our Member revenue in 2014. Payments due to us under the wholesale electric service contracts are pledged and assigned to secure the obligations secured under our Master Indenture. See "Description of the 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 of Directors 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 not withdraw until it has fulfilled all of its obligations to us, including all obligations under its wholesale electric service contract with us. Although we do not have a defined methodology to determine the monetary value of a Member's obligations owed under its wholesale electric service contract, in the past, we have estimated the value of the wholesale electric service contracts based on forecasted revenues less expenses and other offsets over the remaining life of the contract, discounted to net present value.

Members' Service Territories and Customers

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

Customers. Our Members' sales of energy in 2014 were divided by type as follows:

Customer Class	Percentage of MWh Sales	Percentage of Customers
Residential	30.4%	83.0%
Large commercial	38.3	0.1
Small commercial	21.3	12.7
Irrigation	8.3	3.9
Other	1.7	0.3

From 2009 to 2014, our Members experienced an average annual compound growth rate of approximately 0.6 percent in the number of customers and an average annual compound growth rate of 1.8 percent in energy sales. In 2014, the 15 largest customers of our Members represented 18.8 percent of electric energy sales by our Members, although no single customer of our Members represented more than 5 percent of our total energy sales. These customers are primarily in the minerals extraction and transportation business, including natural gas, carbon dioxide and oil production.

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

Relationship with Members

Our Members operate their systems on a not-for-profit basis. We are a membership corporation, and our Members are not 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. In November 2012, three of our New Mexico Members filed protests with the NMPRC of the rate that we filed with the NMPRC in October 2012. 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. The temporary rate rider became effective on October 2, 2014. In March 2013, three of our Colorado Members and several of their large industrial customers filed a complaint at the COPUC alleging that our A-37 rate design was unjust and unreasonable. In 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 to allow the parties time to proceed with more extensive discussions on a global settlement. In February 2015, one of our Colorado Members filed a petition with FERC seeking a declaratory order from FERC finding that its wholesale electric service contract with us is subject to FERC jurisdiction because we have paid off all of our RUS debt. See "Legal Proceedings."

Rates and Regulation

General

We provide electric power to our Members at rates established by our Board of Directors. 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 of Directors has adopted and periodically reviews and revises a Financial Goals and Capital Credits Policy which currently targets rates payable by our Members to produce financial results above the requirements of the Master Indenture. This policy was last revised in May 2015. The policy may be changed by our Board of Directors 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 2014 and 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. Our Member rates for energy and demand are set by our Board of Directors, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through our transmission and distribution system to customers. Prior to 2013, the energy rate was billed based upon a price per kWh of energy delivered. Demand was billed 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 winter peak period. Beginning January 1, 2013, we implemented a new rate design (A-37 rate) that incorporates a seasonal average demand rate, which is calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The new rate design also has a new energy rate that incorporates on-peak and off-peak energy rates for the first time. In November 2014, we implemented an optional rate available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015, with the energy rate billed based upon a price per kWh of energy delivered and the demand billed 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.

Rate Policy

We have developed a Financial Goals and Capital Credits Policy in accordance with, and as described in, the above summary. Pursuant to this policy, management proposes rates that will adequately recover our annual Member revenue requirements contingent upon a budget approved annually by our Board of Directors and load projections. Our Board of Directors 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. Over the past five years, the average rates paid by our Members has increased an average of 1.9 percent per year.

Under the Master Indenture, we are required to establish rates that are reasonably expected to achieve a DSR, as defined in the Master Indenture, 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. See "Description of the Master Indenture—Debt Service Ratio and Rate Covenant; Test for Additional Secured Obligations."

Regulation of Rates

Our rates are established by our Board of Directors. However, we are involved in proceedings in New Mexico and Colorado which could result in oversight of our wholesale rates by the NMPRC and the COPUC. These proceedings are currently suspended for global settlement discussions regarding the wholesale rates payable by our Members. According to New Mexico law, we are also 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. Electric cooperatives are not subject to rate regulation by the FERC under the Federal Power Act, or FPA, if they are financed by RUS; they sell less than 4 million megawatt hours 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 MWh per year. However, one of our Colorado Members filed a petition with FERC seeking a declaratory order from FERC that we are now subject to the general "public utility" regulation because we have paid off all of our RUS debt. See "Legal Proceedings."

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 2014, 62 percent of our energy resources were provided by our generation and 38 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.

Name	Location	% Interest Owned or Leased	Unit Fuel Used	Unit Rating (MW)*	Tri-State's Share (MW)	Year Installed
Coal						
Craig Generating Station Unit 1	Colorado	24.0	Coal	427	102	1980
Craig Generating Station Unit 2	Colorado	24.0	Coal	428	103	1979
Craig Generating Station Unit 3	Colorado	100.0	Coal	448	448	1984
Escalante Generating Station	New Mexico	100.0	Coal	253	253	1984
Laramie River Generating Station Unit 1	Wyoming	24.1	Coal	570	0	1980
Laramie River Generating Station Unit 2	Wyoming	24.1	Coal	570	206	1981
Laramie River Generating Station Unit 3	Wyoming	24.1	Coal	570	206	1982
Springerville Generating Station Unit 3	Arizona	100.0	Coal	416	416	2006
Nucla Generating Station	Colorado	100.0	Coal	100	100	1987
San Juan Generating Station Unit 3	New Mexico	8.2	Coal	488	40	1979
Gas/Oil						
Burlington Generating Station	Colorado	100.0	Oil	100	100	1977
Knutson Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Limon Generating Station	Colorado	100.0	Gas/Oil	140	140	2002
Pyramid Generating Station	New Mexico	100.0	Gas/Oil	160	160	2003
Rifle Generating Station	Colorado	100.0	Gas	85	85	1986
J.M. Shafter Generating Station	Colorado	100.0	Gas	272	272	1994
Brush Cogeneration Partners	Colorado	100.0	Gas	72	72	1994

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

Craig Generating Station ("Craig Station"). Craig Station is a three-unit, 1,303 MW coal-fired electric generating facility located near Craig, Colorado. We own a 24 percent interest in Craig Station Units 1 and 2, which have capacities of 427 MWs and 428 MWs, respectively, and a 100 percent interest in Craig Station Unit 3, which has a capacity of 448 MWs. We are the operating agent for all three units and are responsible for the daily management, administration and maintenance of the facility. The costs associated with operating Craig Station Units 1 and 2 are divided on a pro-rata basis among all the participants. Our total share of Craig Station's capacity is 653 MWs.

Escalante Generating Station ("Escalante Station"). 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 1,710 MW, coal-fired electric generating facility located near Wheatland, Wyoming and operated by Basin. 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. Our share of Laramie River Generating Station's total capacity is 412 MWs.

Springerville 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 Tucson Electric Power Company. Under contractual agreements, Tri-State, as the lessee of Springerville Unit 3, is taking 416 MWs of capacity from the unit and selling 100 MWs of such capacity to Salt River Project Agricultural Improvement and Power District ("Salt River Project"). We own a 51 percent equity interest (including the 1 percent general partner equity interest) in the 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. San Juan Generating Station is a four unit, 1,600 MW, coal-fired electric generating facility located in the Four Corners area of New Mexico. We own an 8.2 percent interest in San Juan Unit 3, which has a capacity of 488 MWs. Our total share of San Juan Unit 3's capacity is approximately 40 MWs. Public Service Company of New Mexico, the New Mexico Environment Department and the EPA have agreed to pursue a plan to comply with federal visibility rules for the San Juan Generating Station. The plan would include the retirement of two units by the end of 2017. We expect that San Juan Generating Station Units 2 and 3 will be retired by December 31, 2017. We are actively engaged in negotiations with the other eight owners of the San Juan Generating Station to establish the terms and conditions under which we will exit active participation in station operations upon retirement of Unit 3. We do not expect these retirement amounts to be material.

Burlington Generating Station. Burlington Generating Station, a 100 MW, oil-fired generating facility located in Burlington, Colorado, is primarily used for back-up generation during periods of peak demand. Burlington Generating Station is wholly owned and operated by us.

Knutson Generating Station. Knutson Generating Station, a two unit, simple cycle combustion turbine, 140 MW, natural gas and oil-fired generating facility located near Brighton, Colorado is wholly owned and operated by us. This facility is under contract to PSCO under a tolling arrangement through April 2016, which is an arrangement whereby the purchaser provides its own natural gas for generation of electricity.

Limon Generating Station. Limon Generating Station, a two unit, simple cycle combustion turbine, 140 MW, natural gas and oil-fired generating facility located near Limon, Colorado, is wholly owned and operated by us. One of the two units is under contract to PSCO under a tolling arrangement through April 2016.

Pyramid Generating Station. Pyramid Generating Station, a four unit, simple cycle combustion turbine, 160 MW, natural gas and oil-fired generating facility located near Lordsburg, New Mexico, is primarily used for back-up generation during periods of peak demand. Pyramid is wholly owned and operated by us.

Rifle Generating Station. Rifle Generating Station, a combined cycle (with three gas turbines and one steam turbine generator) unit, 85 MW, natural gas-fired generating facility located near Rifle, Colorado, is primarily used for back-up generation 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, a combined cycle, 272 MW, natural gas-fired generating facility located near Fort Lupton, Colorado, is primarily used by us for back-up generation during periods of peak demand. 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.

Tolling Arrangements. We have a gas tolling arrangement with AltaGas Brush Energy Inc. to provide intermediate load generating capacity of 72 MWs through December 31, 2019, to meet anticipated Member load requirements. 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. 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 (which terminates September 30, 2024), and two contracts relating to WAPA's Salt Lake City Area Integrated Projects (which 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. 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 program consists of generation and transmission facilities located in the Colorado River Basin. The following table shows the maximum power available from these WAPA resources in the winter season (October—March) and the summer season (April—September):

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

Our purchases of hydroelectric based 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 purchases from Basin to supply power to our Nebraska Members, which are primarily located east of the electrical grid separation and are generally isolated from our generating facilities that are located west of the separation. We have a contract with Basin for a term ending December 31, 2050, to supply the electrical requirements of our Nebraska Members in excess of power supplied by WAPA. As of March 31, 2015, the approximate Nebraska Members’ need from this resource was 311 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 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 Tucson Electric Power Company 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, some of which are discussed below.

In 2009, we entered into a 25-year agreement with Southern Turner Cimarron I, LLC to purchase the electric output from a 30 MW solar photovoltaic generating facility in northeastern New Mexico, which expires in 2035.

In 2009, we also entered into a 20-year agreement with Kit Carson Windpower, LLC to purchase the electric output from a 51 MW wind farm in eastern Colorado, which expires in 2030.

In 2012, we entered into a 20-year agreement with Colorado Highlands Wind, LLC to purchase the electric output from a 67.2 MW wind farm in northeastern Colorado. This agreement was subsequently amended to expand the facility to 91 MW and expires in 2032.

In 2013, we entered into a 25-year agreement with Carousel Wind Farm, LLC to purchase the electric output from a 150 MW wind farm that will be constructed in eastern Colorado. The facility is expected to achieve commercial operation in 2016 when a new transmission line construction project is completed in eastern Colorado.

In June 2015, we entered into a 25-year agreement with Twin Buttes Wind II, LLC to purchase the electric output from a 76 MW wind farm that will be constructed in southeastern Colorado. The facility is expected to achieve commercial operation in 2017.

Other Generation Development

We are in the process of evaluating the 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, 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 2015, we have incurred development costs of approximately $91 million 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 Electric Power Corporation's development contracts with us. While we, along with Sunflower Electric Power Corporation, continue to pursue activities to meet conditions of the construction permit for the project, our Board of Directors has not yet made a decision to participate in the project. We have also acquired real estate interests and water rights for the Colorado Power Project. Through March 2015, we have incurred development costs of approximately $70 million in connection with the Colorado Power Project. We have not 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, some of which are discussed below. We have two existing agreements with PSCO for the sale of contingent power. The agreements are on substantially similar terms. Under the first agreement, we have agreed to supply to PSCO 100 MWs of capacity through March 2017. Under the second agreement, we have agreed to supply to PSCO on an annual basis through 2016, 25 MWs of power from April through September and 75 MWs of power from October through March. These contracts are contingent upon the availability of capacity from Craig Station Units 1, 2, and 3, and Laramie River Generating Station Units 1 and 2. We also have two agreements with PSCO for the output of the two gas turbines at Knutson Generating Station and one gas turbine at the Limon Generating Station for a total of 210 MWs in tolling capacity sales that expire in April 2016. Additionally, we, through our wholly-owned subsidiary, have an agreement with PSCO to sell 122 MWs in tolling capacity from the J.M. Shafer Generating Station that expires in June 2019.

We also have an agreement with Salt River Project to provide 100 MWs of power contingent on the operation of Springerville Unit 3. This agreement continues through August 31, 2036.

Fuel Supply

Coal

We purchase coal under long-term contracts and in spot market transactions. The long-term arrangements provide price stability and the spot market transactions provide the flexibility to purchase coal when it is economically attractive to do so. We have invested in coal mines and coal reserves to provide dedicated coal supplies for Craig Station, Laramie River Generating Station and Nucla

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

Generating Station	Mine(1)	Contract End Date	Annual Tonnage— Tri-State's Share (approximate)
Craig Generating Station Units 1 and 2	Trapper Mine and Colowyo Mine	2020 and 2017, respectively	800,000
Craig Generating Station Unit 3	Colowyo Mine	2017	1,300,000
Escalante Generating 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	San Juan (underground) Mine	2017	180,000
Springerville Unit 3	North Antelope Rochelle Mine	2021	1,250,000 to 1,500,000

(1) Through either our subsidiaries or our membership in third parties, we have an ownership interest in the following mines: Colowyo Mine, Trapper Mine, Dry Fork Mine and New Horizon Mine.

Reclamation Liabilities

In connection with our use of coal derived from coal mining facilities in which we have an ownership interest, including the Trapper Mine, New Horizon Mine, Colowyo Mine and Dry Fork 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. As of March 31, 2015, we have recognized aggregate reclamation liabilities of $53.5 million. We expect our collections to be sufficient to cover the recognized and all projected reclamation liabilities.

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 can 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. 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).

	Direct Flow Amount in Cubic Feet per Second (cfs)	Annual Appropriation (Acre Feet/Year)	Storage Amount (Acre Feet/Year)	Tri-State's Percentage
Surface Water Rights				
Craig Generating Station Units 1&2	75.3		8,310	24%
Craig Generating Station Unit 3	45.9		2,500	100%
Nucla Generating Station	61.1		400	100%
Underground Water Rights				
Burlington Generating Station		39.0		100%
Escalante Generating Station		4,397.4		100%
Knutson Generating Station		31.6		100%
Pyramid Generating Station		1,054.6		100%
Contract Rights				
Craig Generating Station Unit 3			7,000	100%
J.M. Shafer Generating Station		1,412.0		100%
Limon Generating Station			50	100%
Rifle Generating Station			275	100%
Springerville Generating Station		20,000.0		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 draft or final 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 of Directors Policy for Environmental Compliance that is reviewed and updated each year by our Board of Directors. 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 fourteen 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.

On June 2, 2014, the EPA released a comprehensive proposed rule which we refer to as the "Clean Power Plan," aiming to cut carbon dioxide emissions from existing power plants by 30 percent from their 2005 levels by 2030, with an interim goal for the period from 2020 through 2029. The EPA announced intent to finalize the rule during the summer of 2015. Under the proposed rule, each state would have to reduce state-wide carbon dioxide emissions to meet a state specific goal, expressed as an emission rate (pounds/megawatt hour) specified by the EPA. The state-specific target amount was determined by the EPA's interpretation of each state's options to make reductions, including the following: making power plant efficiency upgrades, shifting from coal to natural gas generation, investing in zero- and low-emitting power sources, such as renewable and nuclear energy, and implementing customer energy efficiency programs. The EPA notes that states will have a great deal of flexibility in designing programs to meet their emission reduction targets, including the four approaches noted above or any other measures they choose to adopt, for example, carbon tax and cap-and-trade. We generate power in four states that will each have state specific plans and we provide power to our Members in a fifth state. At this time it is not possible to understand how each utility in each state will be impacted (financially or operationally), as that information will be developed in state specific plans that will be submitted to the EPA by late summer 2016. There is an option in the current proposal to allow states to apply for a one year extension for submission in late summer 2017. The EPA will have one year to review and approve the state plans.

The proposed final state goals in year 2030 under the Clean Power Plan for the five states where we would be impacted are as follows: Arizona—702 lb/MWh; Colorado—1,108 lb/MWh; Nebraska—1,479 lb/MWh; New Mexico—1,048 lb/MWh; and Wyoming—1,714 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. For instance, complying with the Clean Power Plan's emission target for Arizona would require the shutdown of all coal-fired plants in Arizona.

The Clean Power Plan is the most complex and wide-ranging regulation proposed under the Clean Air Act and several groups have filed suit challenging the authority of the EPA to implement the rule. We worked closely with the state environmental agencies, utility commissions, trade groups, and legal representation to develop comments on the proposal, which were submitted to the EPA on December 1, 2014. The outcome of this rule-making process and any subsequent 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), investment in energy efficiency programs and decreased operation, or closure of coal-fired plants.

Air Quality

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

Our facilities are currently equipped with pollution controls that limit emissions of SO_2, NOx, and particulates below the Clean Air Act and permit requirements. We operate coal-fired generating units at Craig Station, Nucla Generating Station and Escalante Station, and we are an owner-participant of coal-fired units at Laramie River Generating Station, which is operated by Basin, and at San Juan Generating Station, which is operated by the Public Service Company of New Mexico, and we lease Springerville Unit 3 (of which we have a 51 percent ownership interest), which is operated by Tucson Electric Power Company. We have pollution control equipment on each of our generating facilities. Craig Station includes scrubbers to remove SO_2, baghouses for particulate removal and low NOx burners. The pollution control equipment at Escalante Station is the same as Craig Station. Springerville Unit 3 is the same as Craig Station with the addition of selective catalytic reduction equipment for NOx control. Nucla Generating Station includes a Circulating Fluidized Bed with limestone for SO_2 removal and baghouses for particulate removal.

Basin and the Public Service Company of New Mexico, as the respective operators for the Laramie River Generating Station and the San Juan Station, are responsible for environmental compliance and reporting for those facilities. Tucson Electric Power Company 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 station units. Springerville Unit 3 was designed and constructed to comply with permitted Best Available Control Technology emission standards. If liabilities arise as a result of a failure of environmental compliance at Laramie River Generating Station, San Juan Generating Station, or Springerville Unit 3, our respective responsibility for those liabilities is governed by the operating agreements for the facilities.

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

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 and NOx emissions by reducing allowable emission rates and by allocating emission allowances to generating facilities for SO_2 emissions based on historical or calculated levels, and reducing allowable NOx emission rates. An emission allowance, which gives the holder the authority to emit one ton of sulfur dioxide during a calendar year, is transferable and can be bought, sold or banked in the years following its issuance. Allowances are issued by the EPA. The aggregate nationwide emissions of sulfur dioxide from all affected units are now capped at 8.95 million tons per year. We receive and hold sufficient SO_2 allowances for compliance with the acid rain program and send excess allowances back to our general account. Allowances have been issued by EPA through compliance year 2044 and we have additional general account allowances that would provide for additional years based on our current usage rate.

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. Therefore, we are now planning for compliance with the rule's emission limits, which will require new emission controls on Craig Station Unit 3, Springerville Unit 3, Escalante Station and Laramie River Generating Station. 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. 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 MATS rule. The Arizona Department of Environmental Quality approved Tucson Electric Power Company's request to extend the MATS mercury compliance date to April 16, 2016 for 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, or NSR, Program Requirements. Over the past decade, the United States Department of Justice, on behalf of the EPA, has brought enforcement actions against owners of coal-fired facilities alleging violations of the NSR provisions of the Clean Air Act in cases where emissions increased without commensurate installation or upgrades of pollution controls. Such enforcement actions were brought against facilities after review by the EPA of operations and maintenance records of the facilities. The EPA has the authority to review such records pursuant to Section 114 of the Clean Air Act. To date, we have not been issued an information request for EPA review of the records of any of our facilities, and therefore, are not involved in any enforcement action from past operational and maintenance activities.

National Ambient Air Quality Standards. In December 2014, the EPA proposed lowering the ambient air quality for ozone from 75 parts per billion (ppb) to a range of 65 to 70 ppb. We filed comments on this proposal in March 2015. Currently, J.M. Shafer Generating Station and Knutson Generating Station are our only generation facilities that are located in an ozone nonattainment area. A more stringent ozone standard may designate new areas as nonattainment and create more difficult permitting and operation conditions for additional generation facilities. Also, implementation of an ozone standard more stringent than the current standard 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 and states were to establish Reasonable Progress Goals in State Implementation Plans to meet a 2064 goal of natural visibility conditions. The amended Regional Haze Rule could require additional controls for particulate matter, SO_2 and NOx emissions from utility sources.

The states were required to develop their regional haze implementation plans by December 2007, identifying the facilities that would need to undergo Best Available Retrofit Technology, or 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 State Implementation Plans establish standards and a timeline for meeting visibility goals. Colorado, New Mexico, Wyoming and Arizona developed State Implementation Plans. Each state was challenged by the EPA and legal processes are ongoing.

Craig Station Units 1 and 2 are subject to BART. In 2007, the State of Colorado determined that the upgraded pollution controls completed in 2004, which include replacement of electrostatic precipitator units with baghouses to increase particulate removal, upgraded scrubbers to increase SO_2 removal and the installation of low NOx burners, met the BART rule; therefore, no additional controls were necessary. The original BART determinations were part of Colorado's State Implementation Plan, which was not approved by the EPA. The EPA told Colorado that the EPA would not approve the State Implementation Plan; therefore the state launched a new State Implementation Plan rulemaking effort. Colorado created a new State Implementation Plan with more stringent SO_2 and NOx emission limits for Craig Station Units 1, 2 and 3. Under the existing, approved State Implementation Plan, we committed to NOx emissions rates that will result in the installation of selective catalytic reduction on Craig Station Unit 2 no later than December 31, 2017. We estimate our cost of such project is approximately $42 million. The existing, approved State Implementation Plan allowed for a not as stringent emissions limit on Craig Station Units 1 and 3, therefore significantly limiting the amount of controls 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 (which will not be final until the entire process has been completed and the new State Implementation Plan has been approved) committing us to a NOx emission rate limit for Craig Station Unit 1 that will require installation of selective catalytic reduction by August 31, 2021, at an estimated cost to us of approximately $42 million. The legislature of Colorado approved the new rule and it was delivered to the EPA for review. In the case of each Craig Station unit, compliance involves capital and operational expenditures for NOx controls.

Any source that emits SO_2, NOx, and particulates and that may contribute to the degradation of visibility in national parks and wilderness areas, identified as Class I areas, could be subject to additional controls. New Mexico opted to comply with SO_2 provisions of the Regional Haze Rule by putting in place a backstop sulfur dioxide trading program. Arizona and New Mexico evaluated NOx emission impacts on visibility and moved forward to develop Reasonable Progress rules for NOx reductions. New Mexico's plan includes the closure of two units at San Juan Generating Station, but neither state's current plan requirements affect our other assets. Wyoming developed a State Implementation Plan that required Low NOx Burners and Overfire Air at Laramie River Generating Station, however the EPA instead proposed a Federal Implementation Plan that also requires Selective Catalytic Reduction. The Federal Implementation Plan is under administrative and legal challenges.

The Regional Haze Rule requires that states assess progress under their state plans every five years, and periodically revise their State Implementation Plans 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.

Greenhouse Gases and the Clean Air Act. On April 2, 2007, the United States Supreme Court issued a decision in *Massachusetts v. Environmental Protection Agency* holding that greenhouse gas emissions are "air pollutants" under the Clean Air Act, requiring the EPA to determine whether greenhouse gases pose a threat to health and welfare. In December 2009, in response to the Court's remand, the EPA issued a final rule under the Clean Air Act determining that greenhouse gases "endanger" human health and the environment and that greenhouse gas emissions from new motor vehicles and engines "cause or contribute" to this endangerment. This determination in turn required the EPA to adopt emission standards for new motor vehicles and engines, which the EPA adopted in early 2010.

The onset of emission limitations for greenhouse gases makes emissions subject to NSR permit requirements of the Clean Air Act. The EPA has adopted a final rule governing the onset of NSR for stationary sources like generating facilities. The rule will apply NSR in phases. Beginning in January 2011, NSR applied to new major sources or major modification of existing major sources if the project would be subject to NSR for at least one non-greenhouse gas pollutant and if the project would increase net greenhouse gas emissions by at least 75,000 tons per year carbon dioxide equivalent ("CO_2e"). In July 2011, NSR applied to sources over 100,000 tons per year CO_2e and to sources over this threshold that make a modification that increases net greenhouse gas emissions by 75,000 tons per year CO_2e. Generating facilities are among the initial group of sources that are subject to these requirements, either for the construction of a new generating facility or as a result of a major modification to an existing power plant. As a result, if a new plant or a modification to an existing plant exceeds these NSR thresholds, the facility will need to install Best Available Control Technology for greenhouse gases, potentially causing a significant increase to capital or operating costs.

For new and existing generating facilities, the EPA proposed emission limits and emission guidelines, respectively, in 2014. The EPA's proposal for existing generating facilities is called the Clean Power Plan and creates state goals, which are to be reached through measures inside and outside of the electric power generation and transmission industry. The proposal is undergoing analysis. The magnitude of the impact on our existing generating facilities is yet to be determined; it will depend on the ultimate deployment of the EPA's final rule and implementation by each of the states in which we have affected assets. The proposal establishes an implementation date of 2020 and a compliance date of 2030.

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 United Nations has a goal to arrive in 2015 at binding targets for future greenhouse gas reductions. If created, it is unknown how such goals would be coordinated with greenhouse gas regulation under the Clean Air Act.

Any such judicial determinations or international agreements could significantly affect the economics of operating certain facilities, specifically our coal-fired facilities. Our fossil fuel-based generating facilities may be affected by proposals by the EPA for greenhouse gas emissions including carbon dioxide. Significant expenditures to our coal-fired generating facilities may be required if stringent regulations of carbon dioxide emissions are implemented. We may be required to switch our fuel supply from coal to natural gas, to implement carbon sequestration programs. Our operations, along with those of many other coal-based utilities, could be materially affected by such regulations. The impact to our operations will depend on the development and implementation of applicable regulations and available technologies and cannot be determined at this time.

Social Cost of Carbon. Estimation and application of a social cost of carbon is of potentially great influence in development of numerous environmental regulations and quantification and consideration of their consequences. Therefore, all aspects of the assumptions and models used should be made available for scrutiny through an open and public review and comment process. Unfortunately, development of the U.S. government's estimate of a social cost of carbon was done in an opaque process between government agencies, and accompanied by a brief technical support document that prevents fully understanding the extent to which uncertainties were appropriately considered and methodologies adequately applied in arriving at a social cost of carbon. The cost has been applied in several dozen rulemakings, including the Clean Power Plant and National Environmental Policy Act, or NEPA, guidance discussed in this document and in many appliance efficiency standards. Development of a social cost of carbon remains controversial and an area of uncertainty.

Water Quality

The Clean Water Act. The Federal Water Pollution Control Act, as amended (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. The EPA proposed a new effluent discharge rule for steam electric generators for which we submitted comments. It appears the rule will have minimal impact on operations at Nucla Generating Station and Rifle Generating Station. 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. Our other facilities have on-site containment ponds where water is evaporated and have no off-site 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 full 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 and/or intake systems that minimize impingement or 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. Currently, we are reviewing the final 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 the Resource Conservation and Recovery Act, 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 Residuals rule was published in the Federal Register on April 17, 2015. The rule contains varying deadlines for the various compliance obligations, some of which must 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 the states do not adopt the rule. We estimate our costs relating to the management of such by-products to be approximately $10 million.

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, we currently provide sufficient energy from renewable sources to meet our Members' obligations under the RPS requirements, and we expect to be able to continue meeting our Members' RPS obligations through 2020, unless a Member exercises its rights under its wholesale electric service contract to meet part of its obligation with generation owned or controlled by such Member (provided it does not exceed 5 percent of such Member's total load).

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.

Electro-Magnetic Fields. A number of electrical industry studies have been conducted regarding the potential long-term health effects resulting from exposure to electro-magnetic fields, or EMF, created by high voltage transmission and distribution equipment. At this time, any relationship between EMF and certain adverse health effects appears inconclusive; however, electric utilities have been experiencing challenges in various forms claiming financial damages associated with electrical equipment which creates EMF. At this time, it is not possible to predict the extent of the cost and other impacts which the EMF concerns may have on electric utilities, including us. In the future, if the scientific community reaches a consensus that EMF presents a health hazard, we may be required to take remedial actions at our facilities. The cost of these actions cannot be estimated with certainty at this time. Such costs, however, could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines is required.

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 2015 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.

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 during the second half of 2015. 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 the 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.

NEPA Revised Draft Guidance for Consideration of Greenhouse Gases. The White House Council on Environmental Quality, or CEQ, in December 2014 issued revised draft guidance for consideration of greenhouse gas emissions and the effects of climate change in NEPA, reviews. Our projects regularly have a federal nexus and require environmental review under NEPA. Projects often require permits and approvals from the Bureau of Land Management, U.S. Forest Service, Office of Surface Mining and

Reclamation and Enforcement, and the U.S. Army Corps of Engineers. In response to the CEQ's notice, we filed comments in March 2015 in which we expressed that the guidance should not be applied retroactively, that quantitative reference points should be removed, that additional clarity is required for defining impacts and bounding analyses, and that the social cost of carbon should not be used in NEPA analyses.

Transmission

As of March 31, 2015, we had a total investment in transmission facilities of approximately $1.19 billion. This investment consists of ownership or interests in approximately 49 miles of 69 kV transmission line, 2,942 miles of 115 kV transmission line, 184 miles of 138 kV transmission line, 1,001 miles of 230 kV transmission line, and 1,220 miles of 345 kV transmission line. The investment also includes ownership or interests in approximately 225 substations and switchyards. 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. 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, Tucson Electric Power Company, Public Service Company of New Mexico and Deseret Generation & Transmission Cooperative. The majority of our transmission facilities operate as part of the Western Interconnection, an interconnected transmission grid which serves the western portion of the United States and Canada. The Western Interconnection consists of transmission assets that link generating facilities to load centers throughout the region. A small portion of our facilities support our load centers in the Eastern Interconnection. We continue to make the capital investment necessary to expand the transmission infrastructure in our service area and participate in many joint projects with other transmission owners within the interconnected grid. We believe these additions insure we can access and deliver into the Eastern and Western Interconnection marketplaces.

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. FERC oversees (1) rates, terms and conditions of interstate wholesale electricity sales and transmission service by public utilities, (2) mergers and acquisitions that involve public utilities, (3) the issuance of securities by public utilities, (4) interlocking directorates among public utilities and between public utilities and certain other entities, (5) operation of wholesale electricity markets, (6) access to transmission facilities, and (7) reliable operation of the transmission grid. In some limited circumstances, FERC may also authorize the siting of new transmission facilities. We are not subject to the general "public utility" regulation of FERC under the FPA because of the exempt status of our Members. Our Members are exempt because they are either cooperatives that are RUS-financed and/or sell less than four million megawatt-hours of electricity per year or utility systems owned by a state government. However, in February 2015, one of our Colorado Members filed a petition with FERC seeking a declaratory order from FERC that we are subject to the general "public utility" regulation because we have paid off all of our RUS debt. 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 the 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, or QFs, co-generators and small power producers. Through our Board policy, our Members have elected to have us make any such purchases from QFs with capacity greater than 25 kilowatts. Purchases from smaller facilities and sales to all such facilities are made by our Members. However, in February 2015, DMEA, one of our Colorado Members filed a petition with FERC seeking a declaratory order finding that DMEA cannot be precluded from purchasing power from a QF larger than 25kw pursuant to the provision of PURPA and FERC regulations. 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, or EPAct 2005, with respect to the provision of certain transmission services. See "—Transmission Planning, Investment and Siting."

On June 3, 2015, our Board of Directors approved us becoming a "transmission-owning member" of the Southwest Power Pool, or SPP, a regional transmission operator, with respect to our transmission facilities and loads that are located in the Eastern Interconnection, which constitute about 4.5 percent of our loads and facilities. Our integration into SPP is expected to become effective January 1, 2016. We expect that SPP will file an application seeking FERC authorization for our membership in November 2015. If the application is approved, we would be subject to greater oversight by FERC, including review of our costs of providing transmission service in the Eastern Interconnection and we would have to abide by the requirements of SPP, which are subject the jurisdiction of FERC.

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 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, Investment and Siting

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 the 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 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.

FERC also has siting authority over transmission lines in some limited circumstances. As amended by the EPAct 2005, the FPA authorizes the Department of Energy, or DOE, to designate corridors in which excessive congestion on the transmission grid adversely affects consumers. FERC may, in very limited circumstances, authorize the siting of transmission lines in those corridors if FERC finds that the traditional, state siting process is inadequate and if the new transmission lines would meet Congress's policy objectives. In 2007, DOE designated two corridors, one in the mid-Atlantic region and one in the Southwest, pursuant to this authority, but both corridors were invalidated by the United States Court of Appeals in 2011. From time to time federal legislation is proposed to address transmission planning and siting authority, but until legislation is enacted into law and FERC or other federal agencies adopt implementing regulations, we cannot predict the impact of these proposals on our business.

Reliability and Cybersecurity

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, protect equipment from sabotage, and follow instructions concerning load shedding. In 2007, FERC also approved limited delegations of authority from NERC to the Midwestern Reliability Organization, or MRO, and to WECC. The delegations authorize each of MRO and WECC to propose regional reliability standards for their respective regions (the Midwest and parts of Canada for MRO, and the West and parts of Canada for WECC) that would supplement or exceed the national standards. NERC also has delegated to each of MRO and WECC authority to monitor and enforce compliance with the regional and national reliability standards, subject to NERC and FERC review.

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

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. As of 2014, we have executed delegation agreements with three Members to assist them with distribution provider reliability compliance responsibilities, but we have and assume no responsibility for penalties that may be assessed with respect to such Members. Each of these Members has agreed to reimburse us for all costs associated with addressing and resolving any audit or enforcement action involving such Member, including any penalties that may be assessed as a result of such Member's failure to comply with a reliability standard. 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. We were subject to a compliance audit jointly administered by WECC (as lead auditor) and MRO in May 2012 to address our compliance with certain of the reliability standards. We are scheduled for future compliance audits by WECC (as lead auditor) and MRO in 2015 and 2018 as part of a three-year audit cycle. The 2009, 2011 and 2012 audits identified some instances in which we were not fully compliant with the audited standards.

As a result, we were assessed minimal penalties that 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 these were first-offenses, none of which individually posed a serious or substantial risk to the reliability of the bulk power system. The penalties and our mitigating actions have been approved by NERC and FERC. We have continued to develop and improve our reliability compliance program.

Like other electric utilities and other owners and operators of critical infrastructure, our operations may be affected by physical threats or attacks, both natural (such as electromagnetic pulses from solar flares) as well as manmade (such as terrorist attacks). We also are subject to the threat of cyber-attack on our facilities, including from terrorists, foreign governments and their agents, hackers, and others.

Potential impacts of a physical or cyber-attack include disruption of operations, operational and financial losses resulting from complete or partial shutdown of critical assets, lost revenues from lost customers and reduced business, and loss of trade secrets and other proprietary information; harm to our reputation due to loss of consumer confidence; significant time and resource investment to respond to, mitigate and recover from the breach or attack; post-event liability and litigation costs; and ongoing compliance monitoring obligations and system improvement expenses. We may have compliance obligations related to new reliability standards addressing the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system. We also intend to comply with existing cybersecurity reliability standards and new statutory and regulatory requirements governing cybersecurity to the extent that they apply to us.

Price Transparency and Market Manipulation

EPAct 2005 amended the FPA to promote price transparency in wholesale energy markets. The amended FPA authorizes FERC to require all market participants, other than those with a de minimis market presence, to disseminate information concerning the availability and price of generation and transmission resources. To date, FERC has focused on requiring greater transparency in the calculation of how much transmission capacity is available, including how much transmission capacity is used to meet local requirements, as well as the submission of quarterly reports on wholesale power sales and transmission transactions. Non-public utilities like us became subject to FERC's quarterly reporting requirement beginning with the third quarter of 2013.

EPAct 2005 also amended the FPA to prohibit manipulation of the energy markets, including by non-public utilities like us. Section 222 of the FPA, as implemented through FERC's regulations, generally prohibits false statements, omissions of material facts and fraudulent or deceitful actions in connection with transactions that are subject to FERC's jurisdiction, that is, wholesale sales and transmission of electric energy in interstate commerce by regulated utilities and other jurisdictional entities. FERC has indicated that the scope of Section 222 extends to non-public utilities to the extent that they engage in activities or transactions that are subject to its jurisdiction or otherwise commit a fraud that affects a transaction by a regulated utility. The knowing and willful submission of false information to FERC, including by a non-public utility, may be penalized as fraud.

Enforcement

EPAct 2005 expanded the scope of FERC enforcement and civil penalty authorities for violations of the FPA. FERC may take specific steps to enforce the FPA, including FERC's regulations, rules and orders promulgated thereunder, and may impose civil penalties of up to $1 million per day, per violation. FERC may seek enforcement in the federal courts, refer matters to the Department of Justice for criminal prosecution, order disgorgement of profits, revoke authorization to sell energy at market-based rates, and impose civil penalties. FERC has noted that it will exercise its enforcement authority in the same manner with respect to all market participants, including both public utilities and non-public utilities.

Competition

The electric utility industry has experienced increasing wholesale competition, enabled by deregulation and revisions to existing regulatory policies, competing energy suppliers, new technology, and other factors. The Energy Policy Act of 1992 amended the FPA to allow for increased competition among wholesale electricity suppliers and increased access to transmission services by such suppliers. On the retail side, except for New Mexico, which repealed its restructuring law in 2003, states in which our Members' service territories are located have not passed 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. We seek to minimize the risk of competition through the territorial service agreement discussed below, price stability, long-term service arrangements, fixed-cost generation and transmission, cost-based coal supplies, and economic diversity among customers. In addition, we serve our Members in rural territories that are less attractive to competitors.

Following the bankruptcy of Colorado-Ute Electric Association, Inc., we entered into an agreement with PSCO and PacifiCorp, two of the principal investor-owned utilities adjacent to our Members' service territory. The agreement, which expires December 31, 2025, 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;
- seek to preserve territorial boundaries when threatened by municipal annexations; and
- confirm and ratify all agreements respecting geographical boundaries (only confirmed and ratified by PSCO and PacifiCorp).

Legal Proceedings

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 our 44 Members by approximately 4.9 percent and from our 12 New Mexico Members 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 is 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 2013 and 2014, the overall impact of the New Mexico Members paying a lower rate was approximately $15.6 million and $16.4 million, respectively. As part of the global settlement, the parties seek to establish a wholesale rate going forward, address the issue of our rate regulation in New Mexico, evaluate the payment of capital credits, evaluate the buyout methodology for Members and perform a cost of service study. 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 COPUC alleging that our A-37 rate design was unjust and unreasonable. On April 4, 2013, we filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over our wholesale rates. The COPUC assigned the matter to an administrative law judge. The judge bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board of Directors, and secondly to hear the facts in the case depending on jurisdiction. The administrative law judge conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the administrative law judge's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the administrative law judge's decision and remanded the case to the administrative law judge to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The administrative law judge entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate. 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 February 9, 2015, DMEA filed a Petition For Declaratory Order with FERC seeking a declaratory order from FERC finding that its wholesale electric service contract with us is subject to FERC jurisdiction because we have paid off all our RUS debt; that the wholesale electric service contract cannot be read to preclude DMEA from purchasing power from a "qualifying resource" pursuant to the provisions of PURPA and FERC regulations thereunder; and that DMEA has the right under FERC's PURPA regulations to negotiate its purchase power price from a "qualifying resource" and to reduce its purchases from us by that amount even if that amount exceeds its contractual obligation to purchase from us. We filed our motion to intervene and protest with FERC related to such petition on March 11, 2015. DMEA filed a motion to answer and answer to our protest on March 26, 2015. We filed a motion for leave to answer and answer to DEMA's answer on April 2, 2015. 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.

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 allege 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 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 are similar. Plaintiffs allege 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 court dismissed the subrogated insurers' claims against us with prejudice. Settlement demands have been 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. In conjunction with the demands, the two plaintiffs have requested mediation. On March 9, 2015, the 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. Trial is currently scheduled to commence in September 2015. 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 intend to vigorously defend these matters and do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

We are involved in two separate water rights proceedings in the State of New Mexico that can 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 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.—Water Supply."

In February 2013, WildEarth Guardians, or WEG, filed suit against the United States Office of Surface Mining, Reclamation and Enforcement, or OSM, in the United States District Court for the District of Colorado, alleging OSM's failure to involve the public and address the economic impacts of coal mining throughout the Rocky Mountain West prior to mine plan approval. The suit alleged unlawful mine plan approval of mines located in Colorado, Montana, New Mexico, and Wyoming. The court granted intervention to several mine owners, including Colowyo Coal and Trapper Mining. The Colowyo Mine plan in WEG's suit was approved in 2007 and the Trapper Mine plan in WEG's suit was approved in 2009. In February 2014, the court agreed to sever the claims and transfer venue for the mines located outside of Colorado. In August 2014, WEG submitted its opening brief on the part of the case that remained in Colorado as Civil Action No. 1:13-cv-00518-RBJ. OSM's responsive brief was filed on October 7, 2014, and Trapper Mining and Colowyo Coal, as intervenors, each filed a responsive brief on October 20, 2014. WEG has asked the court to declare that OSM's approval of the mine plans violated NEPA and for the court to vacate the approvals until OSM demonstrates compliance with the act. Oral arguments took place on April 24, 2015. On May 8, 2015, the court issued an order agreeing with WEG that OSM's approval of the mine plans violated NEPA. The court noted that the majority of the coal covered by the permit at Trapper Mine had already been mined, but ordered that no remaining coal covered by the permit be mined prior to approval of a new permit revision. With respect to the Colowyo Mine, the court determined that immediate vacatur of the Colowyo Mine plan did not outweigh the potential harm. The court deferred an immediate vacatur order for a period of 120 days from May 8, 2015 and expected the OSM during that time to address the deficiencies in the permitting process. Colowyo Coal is working with OSM to respond to the court's order within the 120 days and OSM has undertaken efforts to respond to the court's order within the 120 days. On May 29, 2015, Colowyo Coal filed a Notice of Appeal and Motion to Stay the Order issued by the court. In the event the OSM does not respond to the court's order within the 120 days and the court enters a vacatur order, we are evaluating our options as to alternatives.

On October 19, 2004, WFA and Basin filed a complaint with the Surface Transportation Board, or STB, alleging that the shipping rates instituted by the BNSF Railway Company, or BNSF, for the delivery of coal to the Laramie River Generating Station were unjust and unreasonable. On July 27, 2009, the STB issued its final decision, upholding the complaint and ordering refunds and shipping rate reductions to WFA and Basin. On September 2, 2009, BNSF appealed the STB decision to the United States Court of Appeals for the DC Circuit. Notwithstanding the appeal, BNSF refunded certain amounts and reduced shipping rates. Those reductions were passed on to WFA's and Basin's members, including us. However, those reductions were subject to refund in the event BNSF was ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize the benefit of the receipt of $29.4 million in 2009 in the consolidated statements of operations and have not as of March 31, 2015. Instead, the $29.4 million was recorded as a liability and is included in deferred credits and other liabilities as of March 31, 2015, December 31, 2014 and 2013. On May 11, 2010, the Court of Appeals decided two of the three issues in favor of WFA and Basin. On the third issue, the Court of Appeals remanded the decision back to the STB directing the STB to explain in greater detail why its methodology for allocating variable costs did not double count certain revenue. On June 15, 2012, the STB provided the detailed recommendation on its allocation and affirmed its earlier decision, and BNSF subsequently appealed the STB decision to the Court of Appeals. On January 31, 2014, the Court of Appeals remanded the case back to the STB noting that the STB, under the previous remand, should have also considered whether to apply alternative average total cost to the allocation or provided a reasonable explanation for its actions. On January 28, 2015, BNSF, WFA and Basin filed a joint petition at the STB asking the STB to hold the remanded case in abeyance. In this filing, the parties informed the STB that they had reached a preliminary settlement agreement that called for the dismissal of the case. The parties also informed the STB that the preliminary agreement was contingent upon the parties' development and execution of a rail transportation contract. On May 15, 2015, BNSF, WFA and Basin filed a joint petition at the STB informing the STB that the parties have entered into a rail transportation agreement settling all matters at issue in the proceeding and asking the STB to vacate the rate prescription it entered in the proceeding in 2009, to dismiss the complaint with prejudice, and to discontinue the proceeding. On June 12, 2015, the STB granted the joint petition.

Directors and Executive Officers

Directors

Our Board of Directors is comprised of one representative from each of our 44 Members. Each Member elects its representative to serve on our Board of Directors. 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 of Directors and their ages as of June 17, 2015 are as follows:

NAME	AGE	MEMBER-REPRESENTATIVE
Rick Gordon—Chairman and President	62	Mountain View Electric Association, Inc.
Tony Casados—Vice Chairman	69	Northern Rio Arriba Electric Association, Inc.
Leo Brekel—Secretary	63	Highline Electric Association
Stuart Morgan—Treasurer	69	Wheat Belt Public Power District
Matt M. Brown—Assistant Secretary	63	High Plains Power, Inc.
Julie Kilty—Assistant Secretary	56	Wyrulec Company
Joseph Herrera—Executive Committee	41	Socorro Electric Cooperative, Inc.
William Mollenkopf—Executive Committee	65	Empire Electric Association, Inc.
Joseph Wheeling—Executive Committee	52	La Plata Electric Association, Inc.
Robert Bledsoe	66	K.C. Electric Association, Inc.
Jerry Burnett	68	High West Energy, Inc.
Richard Clifton	73	Carbon Power & Light, Inc.
Wayne Connell	62	Central New Mexico Electric Cooperative, Inc.
Lucas Cordova Jr.	50	Jemez Mountains Electric Cooperative, Inc.
Jack Finnerty	75	Wheatland Rural Electric Association, Inc.
Gary Fuchser	60	Northwest Rural Public Power District
Jack Hammond	80	Niobrara Electric Association, Inc.
Ronald Hilkey	76	White River Electric Association, Inc.
Ralph Hilyard	76	Roosevelt Public Power District
Donald Keairns	56	San Isabel Electric Association, Inc.
Hal Keeler	86	Columbus Electric Cooperative, Inc.
Gary Merrifield	78	Sangre de Cristo Electric Association, Inc.
Thaine Michie	74	Poudre Valley Rural Electric Association, Inc.
Virginia Mondragon	50	Mora-San Miguel Electric Cooperative, Inc.
Chris Morgan	46	Gunnison County Electric Association, Inc.
Richard Newman	64	United Power, Inc.
William Patterson	75	Delta Montrose Electric Association
Stanley Propp	68	Chimney Rock Public Power District
Timothy Rabon	55	Otero County Electric Cooperative, Inc.
Gary Rinker	63	Southwestern Electric Cooperative, Inc.
Arthur Rodarte	66	Kit Carson Electric Cooperative, Inc.
Claudio Romero	68	Continental Divide Electric Cooperative, Inc.
Don Russell	68	Big Horn Electric Company
Brian Schlagel	65	Morgan County Rural Electric Association
Gerald Seward	84	Springer Electric Cooperative, Inc.
Jack Sibold	69	San Miguel Power Association, Inc.
Charles J. Soehner	70	Y-W Electric Association, Inc.
Darryl Sullivan	65	Sierra Electric Cooperative, Inc.
Jerry Thompson	52	Garland Light & Power Company
Carl Trick II	67	Mountain Parks Electric, Inc.
Douglas S. Turner	54	The Midwest Electric Cooperative Corporation
Scott Wolfe	51	San Luis Valley Rural Electric Cooperative, Inc.
William Wright	74	Southeast Colorado Power Association
Phillip Zochol	40	Panhandle Rural Electric Membership Association

Rick Gordon has served on our Board of Directors 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 Committee. Mr. Gordon serves as a director of Mountain View Electric Association, Inc. He also serves as a director of Western Fuels-Colorado, WFA and Trapper Mining. Mr. Gordon owns and operates Gordon Insurance, an independent insurance agency with offices in Limon and Calhan, Colorado.

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

Leo Brekel has served on our Board of Directors since March 2003 and is Secretary of the Board. He is a member of the Executive Committee and serves as Chairman of the Finance 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.

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

Matt M. Brown has served on our Board of Directors 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 of Directors 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 Barx Ranch, LLC.

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

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

Joseph Wheeling has served on our Board of Directors since May 2010. He is a member of the Executive Committee and Finance 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 Gemann Wheeling Cattle Company. Mr. Wheeling is Chairman of the Board of FastTrack Communications. He is also a Director on the Board of MacElvain Energy Inc. and an advisor for Serious Texas BBQ.

Robert Bledsoe has served on our Board of Directors since July 1998. He is a member of the Finance Committee. Mr. Bledsoe serves as Vice President 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 of Directors since November 2013. He is a member of the Engineering and Operations Committee. Mr. Burnett serves as Treasurer of High West Energy, Inc. He is a real estate broker, as well as a farmer, rancher and dairyman in Hereford, Colorado. Mr. Burnett is also on the board of directors of Coldwell Banker and TPE.

Richard Clifton has served on our Board of Directors since June 2009. He is a member of the Finance 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.

Wayne Connell has served on our Board of Directors 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 Western Fuels-Colorado and of Federated Rural Electric Insurance Exchange.

Lucas Cordova Jr. has served on our Board of Directors 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.

Jack Finnerty has served on our Board of Directors 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 Western Fuels-Colorado.

Gary Fuchser has served on our Board of Directors 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.

Jack Hammond has served on our Board of Directors 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 of Directors 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 of Directors 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 Keairns has served on our Board of Directors since April 2012. He is a member of the Finance Committee. Mr. Keairns serves as a director of San Isabel Electric Association, Inc. He was owner and operator of a small grocery business until two years ago. He currently owns and manages several rental properties.

Hal Keeler has served on our Board of Directors since July 2000. He is a member of the Finance 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.

Gary Merrifield has served on our Board of Directors since April 1992. He is a member of the Engineering and Operations Committee. Mr. Merrifield serves as a director of Sangre de Cristo Electric Association, Inc. He is retired.

Thaine Michie has served on our Board of Directors 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 Western Fuels-Colorado.

Virginia Mondragon has served on our Board of Directors 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.

Chris Morgan served on our Board of Directors from June 2012 until February 2015 and he was re-elected to our Board of Directors in April 2015. He is a member of the External Affairs-Member Relations Committee. He serves on the Board of Directors of Gunnison County Electric Association, Inc. and is self-employed. Mr. Morgan is also a director of the Office of Resource Efficiency and of the Rural Transportation Authority. He is also 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 of Directors 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 past President and 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.

William Patterson has served on our Board of Directors since June 2014. He is a member of the External Affairs-Member Relations Committee. Mr. Patterson serves as a director of Delta-Montrose Electric Association. Since 1980 Mr. Patterson has been the Chief Engineer and Chairman of TEI Rock Drills. Mr. Patterson has also served on the City of Montrose, Colorado elected Board (2010-2012).

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

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

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

Arthur Rodarte has served on our Board of Directors since July 2008. He is a member of the Finance 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 of Directors since June 2001. He is a member of the Finance Committee. Mr. Romero serves as a trustee of Continental Divide Electric Cooperative, Inc. He is self-employed in electrical construction. Mr. Romero also serves as a director of WFA.

Don Russell has served on our Board of Directors since March 2012. He is a member of the Finance 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 of Directors since May 2005. He is a member of the Finance 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.

Gerald Seward has served on our Board of Directors since August 2008. He is a member of the Engineering and Operations Committee. Mr. Seward serves as a trustee of Springer Electric Cooperative, Inc. He is a rancher and is currently semi-retired.

Jack Sibold has served on our Board of Directors since June 2014. He is a member of the External Affairs-Member Relations Committee. Mr. Sibold serves as a director of San Miguel Power Association, Inc. He has been a Director of Tri-County Water Conservancy District for the last 3½ years, serving on a committee to develop the hydroelectric plant at the Ridgway Reservoir. 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 of Directors 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 farmer and rancher in Wray, Colorado. Mr. Soehner also serves as a director of Western Fuels-Colorado.

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

Jerry Thompson has served on our Board of Directors since June 2007. He is a member of the Finance 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 of Directors since September 2012. He is a member of the External Affairs-Member Relations Committee. Mr. Trick serves as the Assistant Secretary/Treasurer of Mountain Parks Electric, Inc. He is the Owner, Operator, and 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 of Directors since April 2015. He is a member of the External Affairs-Member Relations Committee. Mr. Turner serves as Vice President of The Midwest Electric Cooperative Corporation. He is a farmer and rancher and the owner and operator of Turn-West Farms, Inc. and Wild Horse Spring Land & Cattle Co. Mr. Turner also serves as President of the Perkins County School Board.

Scott Wolfe has served on our Board of Directors since June 2008. He is a member of the External Affairs-Member Relations Committee. Mr. Wolfe serves as President of San Luis Valley Rural Electric Cooperative, Inc. He has been a farmer for the past 24 years under the entity of Lobo Farm LLC.

William Wright has served on our Board of Directors 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 a farmer..

Phillip Zochol has served on our Board of Directors 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 certain other officers and their ages, as of June 17, 2015:

NAME	AGE	POSITION
Micheal McInnes	62	Chief Executive Officer
Joel Bladow	56	Senior Vice President, Transmission
Patrick L. Bridges	56	Senior Vice President and Chief Financial Officer
Ellen Connor	57	Senior Vice President, Organizational Services and Chief Technology Officer
Jennifer Goss	45	Senior Vice President, Member Relations
Barry Ingold	52	Senior Vice President, Generation
Bradford Nebergall	56	Senior Vice President, Energy Management
Kenneth V. Reif	63	Senior Vice President and General Counsel
Barbara Walz	52	Senior Vice President, Policy & Compliance and Chief Compliance Officer

Micheal S. McInnes, Chief Executive Officer, 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 32 years of experience in the electric utility industry.

Joel Bladow, Senior Vice President Transmission, joined Tri-State in 2006 and has over 32 years of experience in the electric utility industry, including 14 years as a member of WAPA's senior management team. Mr. Bladow has a Master's degree in electrical engineering and is a registered professional engineer in Colorado.

Patrick L. Bridges, Senior Vice President and Chief Financial Officer, joined Tri-State in 2006. Prior to Tri-State, he served as the Vice President and Treasurer of Texas-New Mexico Power Company. Mr. Bridges has more than 31 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, Senior Vice President, Organizational Services and Chief Technology Officer, joined Tri-State in 1999, and has over 32 years of experience in the electric utility industry. Most recently, Ms. Connor served Tri-State 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., 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.

Jennifer Goss, Senior Vice President, Member Relations, joined Tri-State in 2013 and has 16 years of electric utility experience. Prior to serving at Tri-State, she 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[1]s degree in English literature from Assumption College.

Barry Ingold, Senior Vice President, Generation, joined Tri-State in January of 2004 and has served in numerous engineering and management roles. In addition to his 16 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, Senior Vice President, Energy Management, joined Tri-State in 2007 and has 28 years of experience in the energy industry. Prior to Tri-State, he 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.

Kenneth V. Reif, Senior Vice President and General Counsel, joined Tri-State in December 2004. Prior to Tri-State, he 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 35 years of utility experience.

Barbara Walz, Senior Vice President, Policy & Compliance and Chief Compliance Officer, joined Tri-State in 1997 as senior engineer of environmental services. She has held various positions throughout her 17 years with 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 28 years' experience developing and implementing corporate compliance programs.

Compensation Discussion and Analysis

General Philosophy

We are committed to ensuring that our compensation programs are directly linked to our mission and core values since effective utilization of our human capital investment is crucial to maintain a sound financial position while serving our Members. Employee engagement is one of our core values embraced as an enterprise. It is through a highly-engaged and committed workforce that we strive for common goals and achieve desired business results. Through market competitive compensation and benefit programs, career growth opportunities, and a positive work environment, we attract, retain, and engage a well-qualified, innovative, flexible and sustainable workforce. We have defined our strategy and guiding principles for how pay is determined, managed and communicated for employees.

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

The compensation for the Chief Executive Officer is determined by the Board of Directors. On an annual basis the Board of Directors reviews the performance and compensation for the Chief Executive Officer. The Board of Directors 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 of Directors has the authority and ability to award a bonus to the Chief Executive Officer if deemed appropriate.

Retention Agreements

The Chief Executive Officer, with the approval of the Board of Directors, has executed retention agreements for the 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 our subsidiary, Western Fuels-Colorado, working at the New Horizon Mine. This plan is a qualified pension plan under IRC Section 401(a). Benefits, which accrue under the plan, are based upon the employee's base annual salary as of November 15 of the previous year, their years of benefit service and the plan multiplier. In May 2013, we elected to make a voluntary prepayment of $69,840,907 to the Tri-State NRECA Retirement Security Plan and $1,319,507 to the New Horizon Mine Retirement Security Plan.

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 Western Fuels-Colorado 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 Western Fuels-Colorado working at the New Horizon Mine and match 1 percent of employee contributions. There is no match for employees covered by a collective bargaining agreement.

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 attaining 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

We participate in the NRECA Pension Restoration Plan which is 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 plan are: Kenneth J. Anderson, Joel Bladow, Patrick Bridges, Micheal McInnes, Bradford Nebergall, Kenneth Reif and Barbara Walz. 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.
- 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.

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 2014). 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
Kenneth Anderson(2)	2014	$700,003	—	$ 14,641	$ 72,259(3)	$ 786,903
Executive VP and General Manager	2013	$700,003	—	$681,423	$ 29,313	$1,410,739
	2012	$692,791	—	$686,839	$ 28,451	$1,408,081
Micheal McInnes(4)	2014	$529,528	—	—(5)	$ 34,406	$ 563,934
Chief Executive Officer	2013	$386,576	$7,350	$443,113	$ 35,942	$ 872,981
	2012	$374,270	—	$606,201	$ 51,397	$1,031,868
Patrick Bridges	2014	$381,754	—	$ 61,660	$ 46,424	$ 489,838
Senior VP/CFO	2013	$316,064	—	$150,601	$ 47,321	$ 513,986
	2012	$287,194	—	$ 95,892	$ 44,948	$ 428,034
Bradford Nebergall	2014	$349,758	—	$ 60,047	$ 44,086	$ 453,891
Senior VP Energy Management	2013	$339,562	$7,350	$151,115	$ 43,548	$ 541,575
	2012	$327,500	—	$ 83,902	$117,745(6)	$ 529,147
Joel Bladow	2014	$317,473	—	$ 39,148	$ 56,108	$ 412,729
Senior VP, Transmission	2013	$308,218	$7,350	$134,538	$ 56,975	$ 507,081
	2012	$297,270	—	$ 83,455	$ 51,387	$ 432,112
Kenneth Reif	2014	$320,775	—	—(7)	$ 23,513	$ 344,288
Senior VP General Counsel	2013	$306,725	$7,350	$166,862	$ 37,545	$ 518,482
	2012	$287,194	—	$157,709	$ 25,323	$ 470,226

(1) Includes personal use of auto allowance which is grossed up to cover taxes, employer 401(k) contribution, group term life, employer paid premium for medical and dental insurance and payout for unused vacation days.

(2) Mr. Anderson was the Executive Vice President and General Manager through March 10, 2014. After that date, Mr. Anderson was retained at his same salary as a Special Advisor to the Association through January 1, 2015.

(3) Includes $28,000 for vehicle transfer plus $24,415 of tax reimbursement.

(4) Mr. McInnes was named the Interim Executive Vice President and General Manager on April 1, 2014, at which time he was given a salary increase to $500,000/year. He was named the Executive Vice President and General Manager on June 1, 2014 at which time his salary was increased to $600,000/year. His title was changed from Executive Vice President and General Manager to Chief Executive Officer on April 8, 2015.

(5) The change in value from the pension plan was negative $15,729.

(6) Includes lump sum payment for relocation of $50,000 plus $22,547 of tax reimbursement.

(7) Mr. Reif quasi-retired on April 1, 2014 from the Retirement Security Plan at which time the benefit calculation started over on April 2, 2014. Therefore the change in value of the plan from January 1, 2014 to January 1, 2015 was a negative $592,958.

Employment Agreement

On March 10, 2014, we entered into an agreement with Kenneth J. Anderson, the Executive Vice President and General Manager at that time.

Under the agreement, Mr. Anderson resigned his position as our Executive Vice President and General Manager effective March 10, 2014 and agreed to remain employed in the position of Special Advisor to us through January 1, 2015. At that time, Mr. Anderson would terminate his employment with us and serve as a consultant thereafter.

In consideration for Mr. Anderson's continued employment in 2014 as Special Advisor to us, it was agreed that he would continue to receive the same package of salary and benefits that he received as Executive Vice President and General Manager. As part of the agreement, Mr. Anderson received the title to his assigned company vehicle and became responsible for his own insurance and maintenance expenses.

Under the agreement, Mr. Anderson will serve as a consultant to us during the period from January 2, 2015 through December 31, 2015. During this period, Mr. Anderson will continue to provide consulting services to us upon our specific request. In consideration of these consulting services, we will pay Mr. Anderson consulting fees at the rate of $350.00 per hour worked, to a maximum of $50,000 in any calendar month. We have also agreed to reimburse Mr. Anderson for reasonable out of pocket expenses incurred in connection with the performance of consulting services.

As part of the agreement, Mr. Anderson waived and released us and other affiliated entities from all claims, known and unknown, whether negligent or intentional. The agreement includes a non-disparagement clause as well as a non-competition and solicitation clause that will be in effect for the duration of his employment and consulting agreement.

Retention Agreements

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

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

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

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

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, 2014. 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, 2014.

Name	Number of years Credited Service as of December 31, 2014	NRECA Retirement Security Plan Present Value of Accumulated Benefit as December 31, 2014	Pension Restoration Plan Present Value of Accumulated Benefit as of December 31, 2014	Payments During 2014
Kenneth J. Anderson	17 years, 11 months	$ 964,511	$1,533,226	None
Micheal McInnes	31 years, 9 months	$2,030,672	$ 949,942	None
Patrick Bridges	7 years, 3 months	$ 392,743	$ 57,798	None
Bradford Nebergall	6 years, 3 months	$ 346,349	$ 82,383	None
Kenneth Reif	8 months(1)	$ 49,757	$ 84,511	$648,476(1)
Joel Bladow	7 years	$ 366,879	$ 53,733	None

(1) Mr. Reif received a quasi-retirement lump sum on April 1, 2014. On April 2, 2014, Mr. Reif began accruing a new pension plan benefit.

There is a one year waiting period 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, 2014.

Board of Directors Compensation

Chairman and President of the Board

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

1) Director allowances will be 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, which was increased from $500 as of July 2, 2014. The Chairman and President will also be reimbursed for all out-of-pocket expenses incurred on our behalf.

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

Board of Directors

The Board of Directors, 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, which was increased from $400 as of June 4, 2014.

2) The allowance for attendance of a director at any other meeting on Tri-State business is $500 for each day of meeting, which was increased from $400 as of June 4, 2014.

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, which was increased from $400 as of June 4, 2014.

4) There is no allowance for telephone conference meetings.

5) Directors will be 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 shall be reimbursed at the equivalent rates for the use of a personal vehicle, or where appropriate, the commercial plane fair.

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 shall be at the published maximum IRS allowable per diem rate.

Deferred Compensation Program

The Board of Directors, 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 of Directors in 2014 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 2014. Directors are also reimbursed expenses as described above.

Name	2014 Board Fees(1)
William Bird(2)(3)	$ 10,800
Robert Bledsoe	$ 27,400
Leo Brekel	$ 21,200
Matt M. Brown	$ 18,200
Jerry Burnett	$ 18,200
Tony Casados	$ 40,400
Richard Clifton	$ 30,300
Marshall Collins(3)	$ 10,400
Wayne Connell(2)	$ 27,000
Lucas Cordova Jr.	$ 25,400
Jack Finnerty(2)	$ 31,900
Gary Fuchser	$ 17,500
Rick Gordon(4)	$155,997
Ronald Hagan	$ 17,000
Jack Hammond	$ 23,700
Ronald Hilkey	$ 14,600
Ralph Hilyard	$ 21,500
Donald Keairns	$ 23,500
Hal Keeler	$ 26,200
Julie Kilty	$ 23,500
Gary Merrifield	$ 25,800
Thaine Michie(2)	$ 28,300
William Mollenkopf	$ 24,300
Virginia Mondragon	$ 9,500
Chris Morgan	$ 21,900
Stuart Morgan	$ 31,400
Rick Newman	$ 21,500
William Patterson	$ 6,500
Diego Quintana(3)	$ 10,800
Timothy Rabon	$ 15,600
Gary Rinker	$ 14,900
Arthur Rodarte	$ 21,900
Claudio Romero	$ 15,700
Don Russell	$ 22,800
Brian Schlagel	$ 22,400
Gerald Seward	$ 18,700
James Sheridan(3)	$ 3,600
Jack Sibold	$ 10,000
Charles J. Soehner(2)	$ 400
Scott Smith(3)	$ 800
Kevin Stuart	$ 12,800
Darryl Sullivan	$ 27,700
Jerry Thompson	$ 16,600
Carl Trick II	$ 21,800
Joseph Wheeling	$ 29,900
Marcus Wilson(3)	$ 10,000
Scott Wolfe	$ 20,700
William Wright	$ 21,100
Phillip Zochol	$ 10,100

(1) Various Board members have deferred a total of $27,815 of the amounts listed in the table.

(2) Includes fees received for serving as a director of our subsidiary, Western Fuels-Colorado.

(3) Individual ceased serving on the Board of Directors prior to December 31, 2014.

(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

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 2014.

Certain of our directors serve on the board of managers of Western Fuels-Colorado, a subsidiary of ours, and/or the board of directors of other entities in which we have ownership interests, including Basin and Trapper Mining. We have multiple contracts with Western Fuels-Colorado for the purchase of coal for our facilities in the amount of $87.9 million in 2014, which transactions were eliminated through financial consolidation. We also purchased coal for the Yampa Project from Trapper Mining in the amount of $30.6 million in 2014. We also have multiple power contracts with Basin for both the purchase and sale of capacity and energy of $132.2 million for purchase contracts and $6.0 million for sales contracts in 2014.

Other than as described above, in 2014, 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 of Directors 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. 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 October 30, 2014, or the issue date, we sold $250.0 million aggregate principal amount of our 3.70% First Mortgage Bonds, Series 2014E-1, due 2014 and $250.0 million of our 4.70% First Mortgage Bonds, Series 2014E-2, due 2044 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 and outside the United States in compliance with Regulation S under the Securities Act.

On October 30, 2014, we and Goldman, Sachs & Co., 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 330 days after the issue date of the old bonds and to use our commercially reasonably efforts to commence the exchange offer promptly after the declaration of effectiveness. If the registration statement is not declared effective by the SEC within 330 days of the issuance of the old bonds or the exchange offer is not completed within 33 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 , 2015 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. Corporate Trust Operations MAC N9303-121 P.O. Box 1517 Minneapolis, MN 55480	Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303-121 6th St & Marquette Avenue Minneapolis, MN 55479	Wells Fargo Bank, N.A. Corporate Trust Operations Northstar East Building—12th Floor 608 Second Avenue South 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, telecopy, 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

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 (i) 3.70% First Mortgage Bonds, Series 2014E-1, due 2024, and (ii) 4.70% First Mortgage Bonds, Series 2014E-2, due 2044, 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 offering circular 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 new 2014E-1 bonds will bear interest at a rate of 3.70% per annum and the new 2014E-2 bonds will bear interest at a rate of 4.70% per annum. Interest on the bonds accrued from October 30, 2014, payable semi-annually on each May 1 and November 1 (each an "Interest Payment Date") to the persons in whose names they are registered at the close of business on the preceding April 15 and October 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.

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 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 our 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 our 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 Tri-State as trustee with respect thereto shall thereupon cease.

Redemption

At any time 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) 20 basis points with respect to the 2014E-1 Bonds and 25 basis points with respect to the 2014E-2 Bonds;

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

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, in any case, in a manner acceptable under the procedures of DTC, 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.

On or after August 1, 2024 (which is the date that is three months prior to the maturity date of the 2014E-1 bonds), the 2014E-1 bonds will be redeemable upon not less than 30 nor more than 60 days' prior notice given to the holders of the 2014E-1 bonds to be redeemed, at a redemption price equal to 100 percent of the principal amount of the 2014E-1 bonds to be redeemed plus in each case accrued and unpaid interest to the date of redemption.

On or after May 1, 2044 (which is the date that is six months prior to the maturity date of the 2014E-2 bonds), the 2014E-2 bonds will be redeemable upon not less than 30 nor more than 60 days' prior notice given to the holders of the 2014E-2 bonds to be redeemed, at a redemption price equal to 100 percent of the principal amount of the 2014E-2 bonds to be redeemed plus in each case accrued and unpaid interest to the date of redemption.

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 depositary 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, Euroclear and Clearstream and their 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.

Euroclear

Euroclear was created in 1968 to hold securities for its participants and to clear and settle transactions between its participants through simultaneous electronic book-entry delivery against payment, thereby eliminating the need for physical movement of certificates and any risk from lack of simultaneous transfers of securities and cash. Euroclear provides various other services, including securities lending and borrowing, and interfaces with domestic markets in several countries. Euroclear is owned by Euroclear Clearance System Public Limited Company and operated through a license agreement by Euroclear Bank, S.A./N.V., known as the Euroclear Operator. All operations are conducted by the Euroclear Operator, and all Euroclear securities clearance accounts and Euroclear cash accounts are accounts with the Euroclear Operator. Euroclear participants include banks (including central banks), securities brokers and dealers and other professional financial intermediaries and may include the initial purchasers. Indirect access to Euroclear is also available to others that clear through or maintain a custodial relationship with a Euroclear participant, either directly or indirectly.

The Euroclear Operator was granted a banking license by the Belgian Banking and Finance Commission in 2000, authorizing it to carry out banking activities on a global basis. It took over operation of Euroclear from the Brussels, Belgium office of Morgan Guaranty Trust Company of New York on December 31, 2000.

Securities clearance accounts and cash accounts with the Euroclear Operator are governed by the Terms and Conditions Governing Use of Euroclear and the related Operating Procedures of the Euroclear System, and applicable Belgian law (the "Terms and Conditions"). The Terms and Conditions govern transfers of securities and cash within Euroclear, withdrawals of securities and cash from Euroclear, and receipts of payments with respect to securities in Euroclear. All securities in Euroclear are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts. The Euroclear Operator acts under the Terms and Conditions only on behalf of Euroclear participants and has no record of or relationship with persons holding through Euroclear participants.

Distributions with respect to bonds held beneficially through Euroclear will be credited to the cash accounts of Euroclear participants in accordance with the Terms and Conditions, to the extent received by Euroclear.

Clearstream

Clearstream is incorporated under the laws of The Grand Duchy of Luxembourg as a professional depositary. Clearstream holds securities for its participants and facilitates the clearance and settlement of securities transactions between its participants through electronic book-entry changes in accounts of its participants, thereby eliminating the need for physical movement of certificates. Clearstream provides to its participants, among other things, services for safekeeping, administration, clearance and settlement of internationally traded securities and securities lending and borrowing. Clearstream interfaces with domestic markets in several countries. As a professional depositary, Clearstream is subject to regulation by the Luxembourg Monetary Institute. Clearstream participants are financial institutions around the world, including securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations and may include the initial purchasers. Indirect access to Clearstream is also available to others that clear through or maintain a custodial relationship with a Clearstream participant either directly or indirectly.

Distributions with respect to bonds held beneficially through Clearstream will be credited to cash accounts of Clearstream participants in accordance with its rules and procedures, to the extent received by Clearstream.

Definitive Securities

If DTC is at any time unwilling or unable to continue as depositary 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 depositary 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.

Reports

To the extent permitted by the Exchange Act, we will file with the SEC, and make available to the holders or beneficial holders of the bonds, the annual reports and the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that are specified in Sections 13 and 15(d) of the Exchange Act with respect to U.S. issuers within the time periods specified therein or in the relevant forms.

Description of the Master Indenture

General

The new bonds will be issued under our Master Indenture. The terms of the new 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 new 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 Master 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—Equity to Capitalization Ratio 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). 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.

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"). As of March 31, 2015, we had approximately $2.7 billion of outstanding 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, subject to our meeting the historic and pro forma financial tests set forth in the Master Indenture.

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

Under the Master Indenture, our DSR 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 the 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 DSR 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 DSR to be at least 1.10 on an annual basis. If the DSR as reported to the Master Trustee is below the requirement, we must implement a plan within 60 days that is designed to produce a DSR of at least 1.10.

Our failure to achieve the required DSR is not a default under the Master Indenture as long as a plan is timely adopted and being implemented and no payment default has occurred. However, subject to certain limited exceptions, we cannot issue additional Secured Obligations under the Master Indenture unless the DSR for the prior fiscal year (or period of prior 12 consecutive months) is 1.10 and the estimated DSR 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 DSR 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."

Equity to Capitalization Ratio 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 2014 and 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 DSR falls below 1.025 at the end of any fiscal year (or at any other time a calculation of the DSR 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 2014E-1 bonds and the 2014E-2 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 cannot assure you the IRS will not challenge one or more of the tax consequences described in this discussion, and we have not obtained, nor do we intend to obtain, a ruling from the IRS with respect to the U.S. federal income tax consequences described below. 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, or persons who hold the bonds as part of a hedge, conversion transaction, straddle or other risk reduction transaction may be subject to special rules not discussed below.

We urge you to consult your own tax advisors regarding the U.S. federal tax 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 event for U.S. federal income tax purposes. Accordingly, for U.S. federal income tax purposes:

- you will not recognize gain or loss upon receipt of a new bond for an old bond pursuant to the exchange offer;
- your adjusted tax basis in a new bond you receive pursuant to the exchange offer will equal your adjusted tax basis in the old bond exchanged therefor; and
- your holding period for a new bond you receive pursuant to the exchange offer will include your holding period for the old bond exchanged therefor.

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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, appearing in this Prospectus and Registration Statement on Form S-4 described below 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.

When we filed the registration statement, we were not subject to the periodic reporting and other informational requirements of the Securities Exchange Act of 1934. Following effectiveness of the registration statement we will commence filing periodic reports and other information with the SEC. 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, 2014
	($ in thousands)
Total Debt	$2,695,015
Total Margins & Equities	908,086
Total Capitalization	**$3,603,101**
ECR	**25.2%**

Debt Service Ratio

	Year Ended December 31, 2014
	($ in thousands)
Net Margins Available for Debt Service	
Net margins	$ 64,236
Interest expense	120,782
Amortization of debt discount or premium	399
Depreciation, depletion, obsolescence, amortization of property rights, etc.	102,201
Accrued taxes on income	0
Lease expenses	66,381
Income from funds irrevocably deposited	(1,869)
AFUDC and/or capitalized interest	0
Net Margins Available for Debt Service (NMADS)	$352,130
Annual Debt Service Requirements	
Principal of all debt of the Company	123,443
Interest on all debt coming due	107,024
Amortization of balloon payments	8,089
Escrowed payments with respect to defeased debt	(58,478)
Lease payments	81,955
Annual Debt Service Requirement (ADSR)	$262,033
DSR	**1.34**

Tri-State Generation and Transmission Association, Inc.

Consolidated Financial Statements

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

The Board of Directors and Members 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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP
Denver, Colorado
March 3, 2015

Consolidated Statements of Financial Position

As of December 31, (Thousands)	2014	2013
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,193,236	$ 4,965,495
Construction work in progress	206,097	231,374
Total electric plant	5,399,333	5,196,869
Less allowances for depreciation and amortization	(2,129,173)	(2,023,635)
Net electric plant	3,270,160	3,173,234
Other plant	210,694	207,440
Accumulated depreciation and depletion	(58,117)	(38,588)
Net other plant	152,577	168,852
Total property, plant and equipment	3,422,737	3,342,086
Other assets and investments		
Investments in other associations	117,976	128,227
Investments in and advances to coal mines	15,016	13,507
Restricted cash and investments	39,376	118,124
Intangible assets	32,958	40,283
Other noncurrent assets	12,531	12,813
Total other assets and investments	217,857	312,954
Current assets		
Cash and cash equivalents	92,468	193,057
Restricted cash and investments	9,784	125,731
Deposits and advances	22,224	22,569
Accounts receivable—members	105,723	93,590
Other accounts receivable	25,693	31,432
Coal inventory	40,673	43,730
Materials and supplies	80,069	75,477
Total current assets	376,634	585,586
Deferred charges		
Regulatory assets	426,043	248,857
Prepayment—NRECA Retirement and Security Plan	54,665	60,184
Other	178,454	151,839
Total deferred charges	659,162	460,880
Total assets	**$ 4,676,390**	**$ 4,701,506**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 908,669	$ 865,379
Accumulated other comprehensive income (loss)	(828)	3,335
Noncontrolling interest	109,302	110,740
Total equity	1,017,143	979,454
Long-term debt	3,165,960	3,078,140
Total capitalization	4,183,103	4,057,594
Current liabilities		
Member advances	14,576	12,348
Accounts payable	103,177	109,807
Accrued expenses	30,005	30,830
Accrued interest	32,517	24,608
Accrued property taxes	26,010	23,503
Current maturities of long-term debt	94,342	236,588
Total current liabilities	300,627	437,684
Deferred credits and other liabilities		
Regulatory liabilities	45,000	65,000
Deferred income tax liability	17,230	11,859
Intangible liabilities	9,424	12,652
Asset retirement obligations	53,754	52,585
Other	59,121	60,884
Total deferred credits and other liabilities	184,529	202,980
Accumulated postretirement benefit and postemployment obligations	8,131	3,248
Total equity and liabilities	**$ 4,676,390**	**$ 4,701,506**

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

Consolidated Statements of Operations

For the years ended December 31, (Thousands)	2014	2013	2012
Operating revenues			
Member electric sales	$1,101,471	$1,091,103	$1,067,085
Non-member electric sales	197,497	172,102	162,694
Other	96,123	77,958	62,053
	1,395,091	1,341,163	1,291,832
Operating expenses			
Purchased power	327,445	322,059	310,293
Fuel	293,033	287,647	273,169
Production	229,933	209,816	213,674
Transmission	145,396	138,684	136,853
General and administrative	28,591	24,325	22,810
Depreciation and amortization	128,712	121,818	124,861
Coal mining	40,849	29,889	25,027
Other	19,255	18,337	18,930
	1,213,214	1,152,575	1,125,617
Operating margins	**181,877**	**188,588**	**166,215**
Other income			
Interest income	11,076	17,288	24,035
Capital credits from cooperatives	8,684	10,922	7,845
Other income	3,573	3,344	3,563
	23,333	31,554	35,443
Interest expense, net of amounts capitalized	142,357	149,463	151,905
Income taxes	—	—	—
Net margins including noncontrolling interest	62,853	70,679	49,753
Net loss attributable to noncontrolling interest	1,383	2,233	3,042
Net margins attributable to the Association	**$ 64,236**	**$ 72,912**	**$ 52,795**

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

Consolidated Statements of Comprehensive Income

For the years ended December 31, (Thousands)	2014	2013	2012
Net margins including noncontrolling interest	$62,853	$70,679	$49,753
Other comprehensive loss:			
Unrealized gain on securities available for sale	—	278	110
Unrecognized actuarial loss on postretirement benefit obligation	(4,194)	—	—
Reclassification adjustment for actuarial (gain)/loss on postretirement benefit obligation included in net income	31	(358)	(358)
Income tax expense related to components of other comprehensive loss	—	—	—
Other comprehensive loss	(4,163)	(80)	(248)
Comprehensive income including noncontrolling interest	58,690	70,599	49,505
Net comprehensive loss attributable to noncontrolling interest	1,383	2,233	3,042
Comprehensive income attributable to the Association	**$60,073**	**$72,832**	**$52,547**

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

Consolidated Statements of Equity

For the years ended December 31, (Thousands)	2014	2013	2012
Patronage capital equity at beginning of year	$ 865,379	$802,467	$759,672
Net margins attributable to the Association	64,236	72,912	52,795
Retirement of patronage capital	(20,946)	(10,000)	(10,000)
Patronage capital equity at end of year	**908,669**	**865,379**	**802,467**
Accumulated other comprehensive income at beginning of year	3,335	3,415	3,663
Unrealized gain on securities available for sale	—	278	110
Unrecognized actuarial loss on postretirement benefit obligation	(4,194)	—	—
Reclassification adjustment for actuarial (gain)/loss on postretirement benefit obligation included in net income	31	(358)	(358)
Accumulated other comprehensive income at end of year	**(828)**	**3,335**	**3,415**
Noncontrolling interest at beginning of year	110,740	113,027	116,120
Net loss attributable to noncontrolling interest	(1,383)	(2,233)	(3,042)
Equity distribution to noncontrolling interest	(55)	(54)	(51)
Noncontrolling interest at end of year	**109,302**	**110,740**	**113,027**
Total equity at end of year	**$1,017,143**	**$979,454**	**$918,909**

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

Consolidated Statements of Cash Flows

For the years ended December 31, (Thousands)	2014	2013	2012
Operating activities			
Net margins including noncontrolling interest	$ 62,853	$ 70,679	$ 49,753
Adjustments to reconcile net margins to net cash provided by operating activities:			
Depreciation and amortization	126,693	118,776	115,958
Amortization of intangible asset	7,324	7,324	7,324
Amortization of NRECA Retirement and Security Plan prepayment	5,519	5,457	—
Amortization of debt issuance costs	1,356	897	881
Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions	(6,465)	(7,053)	(11,217)
Prepayment—NRECA Retirement and Security Plan	—	(71,160)	—
Recognition of deferred revenue	(20,000)	—	(10,000)
Change in restricted cash and investments	—	(390)	(30,380)
Changes in operating assets and liabilities:			
Accounts receivable	(6,460)	7,000	(12,868)
Coal inventory	3,057	17,524	(6,941)
Materials and supplies	(4,593)	(4,119)	(6,457)
Accounts payable and accrued expenses	(5,923)	13,090	13,111
Accrued interest	7,909	(1,061)	(16,139)
Accrued property taxes	2,507	(189)	(153)
Other	13,076	(5,089)	(110)
Net cash provided by operating activities	**186,853**	**151,686**	**92,762**
Investing activities			
Purchases of plant	(221,613)	(212,703)	(191,651)
Changes in deferred charges	(8,263)	(1,849)	1,290
Proceeds from other investments	15,270	1,578	5,487
Net cash used in investing activities	**(214,606)**	**(212,974)**	**(184,874)**
Financing activities			
Member advances	2,227	(2,129)	(1,385)
Payments of long-term debt	(1,739,835)	(196,490)	(416,780)
Proceeds from issuance of debt	1,674,977	258,873	390,177
Debt refinancing transaction costs	(184,073)	—	—
Decrease in advance payments to RUS	137,727	130,257	123,115
Retirement of patronage capital	(20,582)	(10,711)	(14,869)
Proceeds from investment in securities pledged as collateral	8,723	8,410	8,483
Change in restricted cash and investments	48,000	(15,357)	(32,644)
Net cash provided by (used in) financing activities	**(72,836)**	**172,853**	**56,097**
Net increase (decrease) in cash and cash equivalents	**(100,589)**	**111,565**	**(36,015)**
Cash and cash equivalents—beginning	**193,057**	**81,492**	**117,507**
Cash and cash equivalents—ending	**$ 92,468**	**$ 193,057**	**$ 81,492**
Supplemental information:			
Cash paid for interest	$ 112,388	$ 124,703	$ 142,375

The accompanying notes are an integral part of these consolidated 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 44 member distribution systems that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. The Association also sells a portion of its electric power to other utilities in the region pursuant to long-term contracts and spot sale arrangements. In 2014, 2013 and 2012, total megawatt-hours sold were 18.7, 18.6 and 18.7 million, respectively, of which 83, 82 and 84 percent, respectively, were sold to members. Total revenue from electric sales was $1.3 billion for 2014 and 2013 and $1.2 billion for 2012 of which 85, 86 and 87 percent, respectively, was from member sales. Energy resources were provided by generation and purchased power, of which 63, 64 and 62 percent were from generation for 2014, 2013 and 2012, respectively.

The Association has 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 the Association to sell and deliver to the member and obligates the member to purchase and receive from the Association 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, 2014, 16 members have made such an election.

Power is provided to members at rates determined by the Board of Directors. 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 requirement and an equity to capitalization ratio requirement.

The Association supplies wholesale power to its member distribution systems through the utilization of a portfolio of resources, including generating facilities, long-term purchase contracts and forward, short-term and spot market energy purchases. The Association's generating facilities also include undivided ownership interests in jointly owned generating facilities. See Note 3—Property, Plant and Equipment. In support of its coal generating facilities, the Association has direct ownership and investment in coal mines.

The Association, including its subsidiaries, employs 1,540 people, of which 362 are subject to collective bargaining agreements. None of these agreements expire within one year.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF CONSOLIDATION: The consolidated financial statements include the accounts of the Association, its wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which the Association or its subsidiaries are the primary beneficiaries as described in Note 11—Variable Interest Entities. The consolidated financial statements also include the Association's 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 U.S. generally accepted accounting principles ("GAAP") as applied to regulated enterprises.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

JOINTLY OWNED FACILITIES: The Association owns 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 the Association), the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("BEPC")) 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, the Association's share of the plant asset cost, interest, depreciation and operating expenses is included in the Association's consolidated financial statements.

VARIABLE INTEREST ENTITIES: The Association evaluates its arrangements and relationships with other entities, including its 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 the Association to identify variable interests (contractual, ownership or other financial interests) in other entities and whether any of those entities in which the Association has 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, the Association considers the potential that its arrangements and relationships with other entities provide subordinated financial support, the potential for the Association 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 the Association has a variable interest in meets the criteria of a variable interest entity, the Association must determine whether it is the primary beneficiary of that entity. The primary beneficiary is the entity that has the power to direct the activities of the variable interest entity that most significantly impact the variable interest entity's economic performance, and the obligation to absorb losses or the right to receive benefits from the variable interest entity that could be potentially significant to the variable interest entity. If the Association is determined to be the primary beneficiary of (has a controlling financial interest in) a variable interest entity, then the Association 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: The Association is 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 the Association's Board of Directors, 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 the Association expects to recover from members based on rates approved by the Board of Directors in accordance with the Association's rate

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 the Board of Directors in accordance with the Association's rate policy. The Association recognizes regulatory assets and liabilities as expenses or as a reduction in expenses concurrent with their recovery in rates.

The Association was the lessee under five individual lease agreements of Craig Generating Station Unit 3 with a lease term through 2018. Lease expense was recorded on a straight-line basis over the term of the lease based on total scheduled lease payments to be paid over the life of the lease. Amounts paid in excess of or below recorded lease expense were recorded as prepaid lease expense. In 2002 through 2006, the Association acquired the equity ownership interests in the five separate leases. The acquisitions of these equity interests were accounted for under ownership accounting which would ordinarily have required that the balance of the prepaid lease be recognized as a current expense. However, the current recognition of the prepaid lease expense was deferred under the accounting requirements related to regulated operations and the amount of the deferral is accounted for as a regulatory asset. The regulatory asset for the deferred prepaid lease expense is being amortized into expense each year through the remaining original life of the lease ending in 2018. The amortization of the deferred prepaid lease expense associated with the lease of Craig Generating Station Unit 3 was $6.5 million in 2014, 2013 and 2012 and is included in depreciation and amortization.

The Association was the lessee of the Springerville Generating Station beginning in 2006 for a 34-year lease term. Lease expense was recorded on a straight-line basis over the term of the lease based on total scheduled lease payments to be paid over the life of the lease. Amounts paid in excess of or below recorded lease expense were recorded as prepaid lease expense. In 2009, the Association acquired a controlling interest in the Springerville Unit 3 Partnership LP ("Springerville Partnership"), which is the 100 percent owner of Springerville Unit 3 Holding LLC (the "Owner Lessor") in the Springerville Generating Station Unit 3 Lease. Upon the acquisition, the Springerville Partnership and the Owner Lessor were consolidated by the Association in accordance with the accounting guidance for business combinations and consolidations and pursuant to this guidance the acquisition was accounted for as an acquisition of assets. This consolidation results in the elimination of the Springerville Generating Station Unit 3 Lease expense and therefore, there is no longer lease expense subsequent to the acquisition. Under the asset acquisition approach used in the accounting for this transaction, the pre-acquisition prepaid lease balance of $106.7 million would ordinarily have been expensed as a loss on the acquisition of assets. However, the recognition of the $106.7 million expense was deferred under the accounting requirements related to regulated operations and the amount of the deferral is accounted for as a regulatory asset. The regulatory asset for the deferred prepaid lease expense is being amortized into expense beginning in 2009 through the remaining life of Springerville Generating Station Unit 3 ending in 2056. The amortization of the deferred prepaid lease expense associated with the Springerville Generating Station Unit 3 Lease was $2.3 million in 2014, 2013 and 2012 and is included in depreciation and amortization.

In December 2011, the Association recognized goodwill in the amount of $71.9 million related to the acquisition of Thermo Cogeneration Partnership, LP ("TCP") and in the amount of $45.5 million related to the acquisition of Colowyo Coal Company LP ("Colowyo Coal"). Goodwill represents an asset recognized in a business combination that is initially measured as the excess of the fair value of the acquired business over the fair value of the net identifiable assets acquired. Goodwill is generally treated under GAAP as an indefinite lived asset that is not subject to amortization and is instead required to be evaluated annually for impairment. However, the Association is recovering the goodwill

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

costs pursuant to the accounting requirements related to regulatory accounting. Under this approach, the goodwill amounts are being amortized over specific time periods for recovery in rates. The goodwill of $71.9 million related to the acquisition of TCP is being amortized over the 25-year remaining life of the J.M. Shafer Generating Station since this was the primary asset acquired in the acquisition. This results in annual amortization expense of $2.8 million per year that is included in depreciation and amortization expense. The goodwill of $45.5 million related to the acquisition of Colowyo Coal is being amortized over the 44-year remaining life of the Craig Generating Station since the coal mine was acquired primarily for its use. This results in annual amortization expense of $1.0 million per year that is included in depreciation and amortization expense.

In conjunction with the prepayment of long-term debt during 2014, the Association paid transaction costs of $184.1 million primarily consisting of $165.8 million of make-whole premiums paid to certain lenders. These debt prepayment transaction costs were approved by the Board of Directors to be recorded as regulatory assets and are being amortized into interest expense over the 21.4-year average life of the new debt issued.

The Association has deferred the recognition of revenues in several years. During 2007, the Association deferred the recognition of $20 million of non-member electric sales revenue earned during 2007. $10 million of this deferred revenue was recognized in non-member electric sales revenue in each of the years 2011 and 2012. Therefore, there are no balances remaining to be recognized after December 31, 2012. During 2008, the Association deferred the recognition of $10 million of non-member electric sales revenue earned during 2008. This deferred revenue will be refunded to members through reduced rates when recognized in non-member electric sales revenue in future years, but not beyond 2018. During 2011, the Association deferred the recognition of $55 million of non-member electric sales revenue earned during 2011. $20 million of this deferred revenue was recognized in non-member electric sales revenue in 2014. The remaining $35 million of deferred revenue will be refunded to members through reduced rates when recognized in non-member electric sales revenue in future years, but not beyond 2017.

The regulatory asset related to deferred income tax expense is discussed further in Note 2—Income Taxes.

Regulatory assets and liabilities are as follows (thousands):

	2014	2013
Regulatory assets		
Deferred income tax expense	$ 17,230	$ 11,859
Deferred prepaid lease expense—Craig 3 Lease	22,656	29,129
Deferred prepaid lease expense—Springerville 3 Lease	95,168	97,459
Goodwill—J.M. Shafer	63,390	66,238
Goodwill—Colowyo Coal	43,526	44,172
Deferred debt prepayment transaction costs	184,073	—
	426,043	248,857
Regulatory liabilities		
Deferred revenues	45,000	65,000
Net regulatory asset	$381,043	$183,857

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

SEGMENT REPORTING: The Association is organized for the purpose of supplying wholesale power to its member distribution systems and does 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 its coal generating resources, the Association has direct ownership and investments in coal mines. Resources are allocated and performance is assessed as one operating segment. Therefore, the Association has one reportable segment for financial reporting purposes.

BUSINESS COMBINATIONS: The Association accounts 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. The Association typically engages 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. The Association is 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 4.7, 4.8 and 5.4 percent were used for 2014, 2013 and 2012, respectively. The amount of interest capitalized during construction was $15.0, $13.0 and $15.2 million during 2014, 2013 and 2012, respectively. At the time that units of electric plant are retired, original cost and cost of removal, net of the salvage value, are charged to the allowance for depreciation. Replacements of electric plant that involve less than a designated unit value are charged to maintenance expense when incurred. Electric plant is depreciated based upon estimated depreciation rates and useful lives that are periodically re-evaluated.

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

LEASES: The accounting for lease transactions in conformity with GAAP requires management to make various assumptions, including the discount rate, the fair market value of the leased assets and the estimated useful life, in order to determine whether a lease should be classified as operating or capital.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Association is 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 the Association's 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. The Association is 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 the Association the right to use power generating equipment for a stated period of time. These are included in lease expense on the consolidated statements of operations. See Note 8—Leases.

INVESTMENTS IN OTHER ASSOCIATIONS: Investments in other associations include the Association's investment in the patronage capital of other cooperatives and these investments are accounted for using the cost method. Under this method, the Association's investment in a cooperative increases when a cooperative allocates patronage capital credits to the Association and it decreases when the Association receives a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to the Association based upon the Association's patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (thousands):

	2014	2013
Basin Electric Power Cooperative	$ 80,250	$ 76,139
National Rural Utilities Cooperative Finance Corporation	26,695	41,586
CoBank, ACB	5,518	4,937
Western Fuels Association	2,338	2,478
Other	3,175	3,087
Investments in other associations	$117,976	$128,227

INVESTMENTS IN AND ADVANCES TO COAL MINES: The Association has direct ownership and investments in coal mines to support its coal generating resources. The Association 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. The Association's investment in Trapper Mining is recorded using the cost method as described in Note 2—Investments In Other Associations. In addition, the Association has ownership in Western Fuels Association ("WFA"), which is the owner of Western Fuels-Wyoming ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. The Association, through its ownership in WFA, advances funds to the Dry Fork Mine.

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

	2014	2013
Investment in Trapper Mine	$13,650	$13,235
Advances to Dry Fork Mine	1,366	272
Investments in and advances to coal mines	$15,016	$13,507

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

CASH AND CASH EQUIVALENTS: The Association considers 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 the Association's Board of Directors 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 is therefore a current asset on the statements of financial position. The other funds are noncurrent and are included in other assets and investments.

The Association has 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. A portion of the defeasance investment is for Colowyo Bond debt payments within one year and is, therefore, a current asset on the consolidated statements of financial position. The remainder of the investment is noncurrent.

The United States Department of Agriculture's Rural Utilities Service ("RUS") administers a cushion of credit program under which RUS borrowers may make voluntary irrevocable deposits into a special account. The amounts in the cushion of credit (deposits and earned interest) can only be used to make scheduled payments on loans made or guaranteed by the RUS. The Association participated in this program until the RUS debt was paid off in November 2014. At December 31, 2014 and 2013, the balance in the cushion of credit program was $0 and $137.7 million, respectively.

The Association received $29.4 million in 2009 from the 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 has appealed the decision and the funds are subject to refund in the event BNSF is ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, the Association did not recognize the benefit of the receipt of the $29.4 million in 2009 in the consolidated statements of operations and still has not as of December 31, 2014. The funds were designated by the Association's Board of Directors to be held as restricted cash.

Restricted cash and investments are as follows (thousands):

	2014	2013
Funds restricted for payment of debt—Platte County bonds	$ —	$ 48,000
Investments in securities pledged as collateral	9,192	9,242
Funds restricted by contract	592	390
RUS cushion of credit	—	68,099
Restricted cash and investments—current	9,784	125,731
BNSF settlement	29,381	29,381
Funds restricted by contract	1,000	1,000
Investments in securities pledged as collateral	8,995	18,114
RUS cushion of credit	—	69,629
Restricted cash and investments—noncurrent	39,376	118,124
Total restricted cash and investments	$49,160	$243,855

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

FAIR VALUE: Accounting guidance defines fair value 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 measurements, a three-tier fair value hierarchy for measuring fair value was established which prioritizes the inputs used in measuring fair value. 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 are 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: The Association holds 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, 2014, the cost and estimated fair value of the investments based upon their active market value (Level 1 inputs) were $1.1 and $1.4 million, respectively, with a net unrealized gain balance of $254,000. At December 31, 2013, the cost and estimated fair value of the investments were $1.2 and $1.5 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, 2014 and 2013 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.

The Association holds 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, 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. As of December 31, 2013, the defeasance investment of $27.4 million consisted of a principal amount of $25.1 million, an unamortized premium of $900,000 and cash of $1.4 million.

INVENTORIES: Coal inventories at the Association's owned generating stations are stated at LIFO (last-in, first-out) cost and were $22.2 and $25.6 million at December 31, 2014 and 2013, respectively. The remaining coal inventories, other fuel, and materials and supplies inventories are stated at average cost. The Association realized lower coal fuel expense in 2014 and 2013 of $596,000 and $5.1 million, respectively, as a result of a LIFO inventory liquidation.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

OTHER DEFERRED CHARGES: The Association makes expenditures for preliminary surveys, plans 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 and, if large, it is expected that the expense would be deferred as a regulatory asset to be recovered in rates. As of December 31, 2014, preliminary survey and investigation was primarily comprised of expenditures for the Holcomb Station Project of $82.0 million (see Note 12—Commitments and Contingencies—Legal) and the Eastern Plains Transmission Project of $27.3 million.

The Association makes advance payment to the operating agents of jointly owned facilities. See Note 3—Property, Plant and Equipment—Jointly Owned Facilities.

The Association accounts for debt issuance costs as deferred debt expense. Deferred debt expense is amortized to expense using an effective interest method over the life of the respective debt issuance. In October 2014, Tri-State entered into an agreement with the 2011 Credit Agreement lenders to increase the commitment amount from $500 million to $750 million and grant a one-year extension of the maturity date to July 26, 2019. As a result of this transaction, the Association recorded an additional $1.3 million of debt issuance costs in deferred charges that are being amortized to interest expense using an effective interest method over the life of the modified 2011 Credit Agreement.

During 2014, the Association refinanced a significant portion of its long-term debt (see Note 5—Long- Term Debt). Debt issuance costs of $13.0 million were incurred as a result of this refinancing. These debt issuance costs are included in other deferred charges and are being amortized to expense using an effective interest method over the weighted average life of the respective debt issuances.

The following other deferred charges are reflected on the Association's consolidated statements of financial position (thousands):

	2014	2013
Preliminary survey and investigation	$131,693	$126,572
Advances to operating agents of jointly owned facilities	20,567	12,303
Debt issuance costs	22,254	8,923
Other	3,940	4,041
Total other deferred charges	$178,454	$151,839

ASSET RETIREMENT OBLIGATIONS: The Association accounts 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, the Association determines 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, the Association will apply payment against the estimated liability and incur a gain

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

or loss if the actual retirement costs differ from the estimated recorded liability. Asset retirement obligations are included in deferred credits and other liabilities.

Coal mines: The Association has asset retirement obligations for the final reclamation costs and post-reclamation monitoring related to the New Horizon Mine, the Fort Union Mine and the Colowyo Mine.

Fossil steam generation: The Association, including its undivided interest in jointly owned facilities, has asset retirement obligations related to equipment, dams, ponds, wells and underground storage tanks at the fossil steam generating stations.

Transmission: The Association has 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):

	2014	2013
Asset retirement obligation at beginning of year	$52,585	$44,488
Liabilities incurred	1,366	4,623
Liabilities settled	(5,729)	(195)
Accretion expense	2,250	2,675
Change in cash flow estimate	3,282	994
Asset retirement obligation at end of year	$53,754	$52,585

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

OTHER DEFERRED CREDITS AND OTHER LIABILITIES: The Association received $29.4 million in 2009 from the BNSF as a reduction of prior coal delivery shipping charges as the result of the decision of the STB. However, BNSF has appealed the decision. Due to uncertainties regarding the ultimate outcome of this matter, the Association did not recognize the benefit of the receipt of the $29.4 million in 2009 in the consolidated statements of operations and still has not as of December 31, 2014. See Note 12—Commitments and Contingencies—Legal.

The Association has received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits. The Association has received upfront payments from others for the use of optical fiber and these are reflected in unearned revenue until recognized over the life of the agreement.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The following other deferred credits and other liabilities are reflected on the Association's consolidated statements of financial position (thousands):

	2014	2013
BNSF rate settlement proceeds not recognized in income	$29,381	$29,381
Customer deposits	2,464	3,292
Unearned revenue	4,210	4,546
Other deferred credits	23,066	23,665
Total other deferred credits and other liabilities	$59,121	$60,884

MEMBERSHIPS: There are 44 $5 memberships outstanding at December 31, 2014 and 2013.

PATRONAGE CAPITAL: Net margins of the Association are treated as advances of capital by the members and are allocated to the members on the basis of their electricity purchases from the Association. 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 the Association's members and is distributed through patronage capital retirements when the Association's Board of Directors 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 the Association charges other energy companies for transmitting electricity over the Association's transmission lines. The lease revenue is primarily from certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to others the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project. The associated Colowyo Mine expenses are included in coal mine operating expense, depreciation and interest expense on the consolidated statements of operations.

INCOME TAXES: The Association is a non-exempt cooperative subject to federal and state taxation and, as a cooperative, is 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.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

INTERCHANGE POWER: The Association occasionally engages 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 the Association is in a net energy advance position, the advanced energy balance is recorded as an asset. If the Association owes energy, the net energy balance owed to others is recorded as a liability. The net activity for the year is included in purchased power expense. The interchange liability balance of $1.5 and $2.0 million at December 31, 2014 and 2013, respectively, is included in accounts payable. The net interchange activity recorded in purchased power expense was $(452,500), $2.6 million and $(1.3) million in 2014, 2013 and 2012, respectively.

EVALUATION OF SUBSEQUENT EVENTS: The Association evaluated subsequent events through March 3, 2015, which represents when the consolidated financial statements were available to be issued.

NEW ACCOUNTING PRONOUNCEMENTS: In February 2013, the FASB issued ASU 2013-02, *Comprehensive Income (Topic 220): Reporting Amounts Reclassified Out of Accumulated Other Comprehensive Income*. This ASU requires an entity to present on the face of the financial statements or in a single note significant amounts reclassified from each component of accumulated other comprehensive income and the income statement line items affected by the reclassification. ASU 2013-02 is effective for the Association for the fiscal year beginning January 1, 2014. The adoption of this update did not have a material impact on the Association's financial position or results of operations.

In July 2013, the FASB issued ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*. This amendment provides authoritative guidance on the financial statement presentation of unrecognized tax benefits when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. ASU 2013-11 is effective for the Association for the fiscal year beginning January 1, 2015 and must be applied on a prospective basis for all unrecognized tax benefits that exist at the effective date. The adoption of this update is not expected to have a material impact on the Association's financial position or results or operations.

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606).* This amendment replaces current revenue guidance, based on risks and rewards, with a transfer of control model. The core principle under this new model states that revenue should be recognized to depict the transfer of promised 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, ASU 2014-09 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. ASU 2014-09 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. ASU 2014-09 is effective for the fiscal year beginning January 1, 2017 for public entities and January 1, 2018 for nonpublic entities with early application not permitted. The Association is currently considering the effects of adopting this amendment.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

In November 2014, the FASB issued ASU 2014-17, *Business Combinations (Topic 805) : Pushdown Accounting*. This ASU provides an acquired entity with an option to apply pushdown accounting in its separate financial statements for each change-in-control event. If the entity elects pushdown accounting for an individual change-in-control event, that election is irrevocable. If pushdown accounting is not applied during the reporting period in which the change-in-control event occurs, an acquired entity still will have the option to apply pushdown accounting in a subsequent period to the most recent change-in-control event. ASU 2014-17 was effective upon issuance. The adoption of this update did not have a material impact on the Association's financial position or results of operations.

RECLASSIFICATIONS: Certain reclassifications have been made to the prior year financial statements to conform to the 2014 presentations.

NOTE 3—PROPERTY, PLANT AND EQUIPMENT

The Association's property, plant and equipment consists of electric plant and other plant. Both of these are discussed below and are included on the consolidated statements of financial position.

ELECTRIC PLANT: The Association's 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			2014	2013
Generation plant	0.44%	to	3.16%	$ 3,379,305	$ 3,267,742
Transmission plant	2.00%	to	2.88%	1,161,462	1,095,554
General plant	3.00%	to	33.33%	392,963	358,755
Other	2.80%	to	5.60%	259,506	243,444
Electric plant in service (at cost)				5,193,236	4,965,495
Construction work in progress				206,097	231,374
Less allowances for depreciation and amortization				(2,129,173)	(2,023,635)
Electric plant				$ 3,270,160	$ 3,173,234

At December 31, 2014, the Association had $67.4 million of commitments to complete construction projects, of which approximately $56.3, $8.4 and $2.7 million are expected to be incurred in 2015, 2016 and 2017, respectively.

JOINTLY OWNED FACILITIES: The Association's share in each jointly owned facility is as follows as of December 31, 2014 (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%	$345,302	$229,960	$ 8,884
MBPP—Laramie River Station	24.13%	387,907	288,731	3,770
San Juan Project—San Juan Unit 3	8.20%	73,275	55,880	10,289
Total		$806,484	$574,571	$22,943

NOTE 3—PROPERTY, PLANT AND EQUIPMENT (Continued)

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).

The Association owns 99 percent of Western Fuels-Colorado, a limited liability company organized for the purpose of acquiring coal reserves and supplying coal to the Association, which is the owner and operator of the New Horizon Mine near Nucla, Colorado. Western Fuels-Colorado also owns Colowyo Coal Company LP ("Colowyo Coal"), which is the owner and operator of the Colowyo Mine, a large surface coal mine near Craig, Colorado. The Association also owns a 50 percent undivided ownership in the land and the rights to mine the property known as Fort Union Mine. The Association's share of the coal provided from these mines is primarily used by the Association for generation at its generating facilities. The expenses related to this coal used by the Association are included in fuel expense on the consolidated statements of operations.

Other plant assets are as follows (thousands):

	2014	2013
Colowyo Mine assets	$152,549	$150,847
New Horizon Mine assets	44,812	43,364
Fort Union Mine assets	2,007	1,903
Accumulated depreciation and depletion	(52,580)	(33,365)
Net mine assets	146,788	162,749
Non-utility assets	11,326	11,326
Accumulated depreciation	(5,537)	(5,223)
Net non-utility assets	5,789	6,103
Net other plant	$152,577	$168,852

NOTE 4—INTANGIBLES

INTANGIBLE ASSETS: The December 2011 acquisition of TCP resulted in the Association 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

NOTE 4—INTANGIBLES (Continued)

years 2014, 2013 and 2012 and will be recognized over each of the next five years and thereafter as follows (thousands):

2015	$ 7,324
2016	7,324
2017	7,324
2018	7,324
2019	3,662
	$32,958

INTANGIBLE LIABILITIES: The December 2011 acquisition of Colowyo Coal resulted in the Association recording an intangible liability of $18.0 million relating to a contractual obligation that Colowyo Coal has to sell coal to the other owner participants in the Yampa Project (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 $9.4 and $12.7 million as of December 31, 2014 and 2013, respectively, is included in deferred credits and other liabilities. The amortization of the Colowyo Coal intangible liability is accounted for as an increase in other operating revenue. An amortization benefit of $3.2, $2.5 and $2.6 million was recognized in 2014, 2013 and 2012, respectively, and the recognition of the benefit over the next three years is estimated to be as follows (thousands):

2015	$3,125
2016	3,125
2017	3,174
	$9,424

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 one unsecured note. Substantially all the assets, rents, revenues and margins of the Association are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Generating Station Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance discussed later in this note and an unconditional guarantee of the Association. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement and an equity to capitalization ratio requirement.

NOTE 5—LONG-TERM DEBT (Continued)

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

	2014	2013
Mortgage notes payable		
2% RUS, due through 2017	$ —	$ 165
5% RUS, due through 2026	—	4,988
1.95% to 10.81% FFB, 4.19% average for 2014, due through 2047	—	1,316,042
3.66% to 8.08% CFC, 5.96% average for 2014, due through 2028	92,977	114,924
2.63% to 6.17% CoBank, ACB, 4.35% average for 2014, due through 2042	287,798	228,835
First Mortgage Bonds, Series 2014E-1, 3.70% due 2024	249,897	—
First Mortgage Bonds, Series 2014E-2, 4.70% due 2044	248,688	—
First Mortgage Bonds, Series 2010A, 6.00% due 2040	499,322	499,323
First Mortgage Obligation, Series 2014B, Tranche 1, 3.90%, due through 2033	180,000	—
First Mortgage Obligation Series 2014B, Tranche 2, 4.30%, due through 2039	20,000	—
First Mortgage Obligation Series 2014B, Tranche 3, 4.45%, due through 2045	550,000	—
First Mortgage Obligation, Series 2009C, Tranche 1, 6.00%, due through 2019	135,714	162,857
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 2014, due through 2026	687	728
Variable rate CFC, LIBOR-based term loan, 1.48% average for 2014, due through 2049	102,220	—
Variable rate CoBank, ACB, LIBOR-based term loan, 1.74% average for 2014, due through 2044	102,220	—
Variable rate Grantor Trust Obligations, as determined by CFC, 0.48% average for 2014, due through 2017	—	17,205
Variable rate, 2011 Credit Agreement, LIBOR-based revolving credit, 1.25% average for 2014, due through 2019	50,000	130,000
Pollution control revenue bonds		
Platte County, WY Daily Adjustable Rate Series 1984, 0.05% average for 2014, due 2014	—	48,000
City of Gallup, NM, 5.00%, Series 2005, due through 2017	16,155	21,160
Moffat County, CO Variable Rate Demand Series 2009, 0.06% average for 2014, due 2036	46,800	46,800
Springerville certificates		
Series A, 6.04%, due through 2018	126,635	160,774
Series B, 7.14%, due through 2033	421,429	422,566
Colowyo Coal		
Colowyo Bonds, 10.19%, due through 2016	17,224	25,895
Mine Equipment Loans, 7.75%, due through 2014	—	1,883
Other	2,536	2,583
Total debt	$3,260,302	$3,314,728
Less current maturities	(94,342)	(236,588)
Long-term debt	$3,165,960	$3,078,140

NOTE 5—LONG-TERM DEBT (Continued)

In 2014, the Association refinanced a significant portion of its outstanding long-term debt through a series of various debt issuances. On September 30, 2014, the Association prepaid all amounts due directly to the Rural Utilities Service in the aggregate amount of $4.3 million. On October 30, 2014, the Association issued the Series 2014 E-1 and Series 2014 E-2 first mortgage obligations in an aggregate amount of $500 million. The Series 2014 E-1 and Series 2014 E-2 were issued with Securities and Exchange Commission registration rights. On October 31, 2014, the Association issued the Series 2014B first mortgage obligations through a private placement of secured notes in three separate tranches totaling $750 million. Also, on October 31, 2014, the Association issued fixed rate and variable rate notes to CoBank, ACB (“CoBank”) in the amounts of $68.3 million and $102.2 million, respectively, and fixed rate and variable rate notes to National Rural Utilities Cooperative Finance Corporation (“CFC”) in the amounts of $68.3 million and $102.2 million, respectively. Proceeds from these issuances totaled $1.59 billion. On November 5, 2014, the Association used the proceeds to prepay all outstanding long-term debt due to the Federal Financing Bank (“FFB”) in an aggregate principal amount of $1.26 billion, certain amounts due to CFC totaling $68.9 million and amounts due under grantor trust certificates totaling $12.9 million. Along with the prepayment of the FFB debt, the Association also terminated any outstanding commitments from the FFB.

In conjunction with the prepayment of long-term debt during 2014, the Association paid transaction costs of $184.1 million primarily consisting of $165.8 million of make-whole premiums paid to certain lenders. These debt prepayment transaction costs were approved by the Board of Directors to be recorded as regulatory assets.

In February 2009, the Association refunded the Moffat County, CO Weekly Adjustable Rate Series 1984 Bonds and issued the $46.8 million Moffat County, CO, Variable Rate Demand Pollution Control Revenue Refunding Bonds, Series 2009 (“Series 2009 Bonds”) with a 364-day, direct pay letter of credit provided by Bank of America, N.A. (“Bank of America”). In December 2014, the letter of credit from Bank of America was extended for an additional 364 days to mature in January 2016.

The Association has a 51 percent equity interest in the Springerville Partnership that was accounted for as an acquisition of assets and is consolidated in accordance with the accounting guidance for business combinations and consolidations (see Note 8—Leases). Therefore, 100 percent of the assets, liabilities and expenses of the Springerville Partnership are included in the consolidated financial statements of the Association. This includes 100 percent of the Tri-State Generation and Transmission Association, Inc. 2003 Series A and Series B Pass Through Trust Certificates which, along with owner equity, provided funding for the construction of Springerville Generating Station Unit 3.

At December 31, 2013, the Association had two unused committed lines of credit totaling $75 million. Both lines of credit were terminated in October 2014.

In July 2011, the Association entered into an agreement (the “2011 Credit Agreement”) with Bank of America as administrative agent and CoBank and Bank of America as joint lead arrangers for a secured revolving credit facility with a total commitment of $500 million for a term of five years that was to expire in July 2016. In November 2013, the term of the 2011 Credit Agreement was extended for two years to expire in July 2018. In October 2014, the 2011 Credit Agreement was further amended to increase the total commitment to $750 million and to extend the term for one year to expire in July 2019.

NOTE 5—LONG-TERM DEBT (Continued)

Annual maturities of total debt at December 31, 2014 are as follows (thousands):

2015	$ 94,342
2016	92,882
2017	109,618
2018	80,146
2019	149,295
Thereafter	2,734,019
	$3,260,302

NOTE 6—FAIR VALUE OF LONG-TERM DEBT

The fair values of long-term debt were estimated using discounted cash flow analyses based on the Association's 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 the Association's long-term debt are as follows (thousands):

	2014		2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
RUS	$ —	$ —	$ 5,153	$ 5,876
FFB	—	—	1,316,053	1,382,915
CFC	195,884	258,180	115,652	124,556
First Mortgage Bonds, Series 2014E-1 and E-2	498,585	524,293	—	—
First Mortgage Bonds, Series 2010A	499,322	632,365	499,323	567,630
First Mortgage Obligations, Series 2014B	750,000	784,126	—	—
First Mortgage Obligations, Series 2009C	245,714	277,061	272,857	314,902
Pollution control revenue bonds	62,955	63,197	115,960	116,377
2011 Credit Agreement	50,000	49,323	130,000	128,016
Grantor Trust Obligations	—	—	17,205	17,128
CoBank, ACB	390,018	398,839	228,835	224,580
Springerville certificates	548,064	709,278	583,340	746,766
Colowyo Bonds	17,224	17,127	25,895	26,389
Mine Equipment Loans	—	—	1,883	1,908
Other	2,536	2,724	2,572	2,976
	$3,260,302	$3,716,513	$3,314,728	$3,660,019

NOTE 7—INCOME TAXES

The Association had no income tax expense or benefit in 2014, 2013 and 2012.

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

NOTE 7—INCOME TAXES (Continued)

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 the Association's net deferred tax liability are as follows (thousands):

	2014	2013
Deferred tax assets		
Safe harbor lease receivables	$ 38,218	$ 40,225
Net operating loss carryforwards	131,935	58,333
Alternative minimum tax credit carryforwards	3,834	3,834
Deferred debt charges	830	1,377
Deferred revenues	16,933	24,460
Colowyo Coal- coal contract intangible liability	3,547	4,761
Other	46,026	46,867
	241,323	179,857
Deferred tax liabilities		
Basis differences- property, plant and equipment	152,497	158,789
Capital credits from other associations	36,790	32,927
Deferred debt prepayment transaction costs	69,266	—
	258,553	191,716
Net deferred tax liability	$(17,230)	$(11,859)

The $5.3 million increase in the net deferred tax liability from $11.9 million at December 31, 2013 to $17.2 million at December 31, 2014 is not recognized as a tax expense in 2014 due to the Association's 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 $17.2 million and $11.9 million at December 31, 2014 and 2013, respectively.

NOTE 7—INCOME TAXES (Continued)

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

	2014	2013	2012
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	1.40	(6.74)	(7.38)
Postretirement medical actuarial gains and losses	2.44	0.18	(2.45)
Various book tax differences	4.52	8.93	8.27
Regulatory treatment of deferred taxes	(8.36)	(2.37)	1.56
Effective tax rate	0.00%	0.00%	0.00%

The Association had a taxable loss of $197.2 million for 2014. At December 31, 2014, the Association has a federal net operating loss carryforward of $350.6 million which, if not utilized, will expire between 2030 and 2034. The future reversal of existing temporary differences will more-likely-than-not enable the realization of the net operating loss carryforward. The Association has $3.8 million of alternative minimum tax credit carryforwards at December 31, 2014 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. The Association 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.

The Association files 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 2011 forward. The Association does not have any liabilities recorded for uncertain tax positions.

NOTE 8—LEASES

LESSOR—GAS TOLLING ARRANGEMENTS: The Association is 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 the Association's 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

NOTE 8—LEASES (Continued)

four-year period beginning May 2009 through April 2013 and the Knutson contract was suspended for a three-year period beginning May 2010 through April 2013 to allow the Association 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. The Association also had a similar tolling arrangement with a third party through September 30, 2014 involving one of the four 40-megawatt units at the Association's Pyramid Generating Station. The revenues from these operating leases of $30.6, $25.8 and $13.2 million for 2014, 2013 and 2012, 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 $232 and $108 million, respectively, as of December 31, 2014, and of $229 and $105 million, respectively, as of December 31, 2013.

The minimum future lease revenues under these gas tolling arrangements at December 31, 2014 are as follows (thousands):

2015	$32,409
2016	18,389
2017	11,379
2018	11,379
2019	5,690
	$79,246

LESSEE—GAS TOLLING ARRANGEMENT: The Association is 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 the Association the right to use power generating equipment for a stated period of time. Under this agreement, the Association directs the use of 72 megawatts at the Brush Generating Station for a 10-year term ending December 31, 2019 and provides its own natural gas for generation of electricity. The expense for the Brush operating lease of $5.3 million for each of the years 2014, 2013 and 2012 is included in other operating expenses on the consolidated statements of operations. The Association's operating lease commitments for this gas tolling arrangement at December 31, 2014 are as follows (thousands):

2015	$ 5,359
2016	5,519
2017	5,678
2018	5,855
2019	6,031
	$28,442

NOTE 9—RELATED PARTIES

BASIN ELECTRIC POWER COOPERATIVE: BEPC is a wholesale power supply cooperative of which the Association is a member. The Association purchased power from BEPC at a cost of $133, $136 and $138 million in 2014, 2013 and 2012, respectively. The Association's investment in BEPC was $80.3 and $76.1 million at December 31, 2014 and 2013, respectively, and is included in investments in other associations. The Association's share of BEPC capital credit allocations was $5.0, $6.3 and $5.5 million in 2014, 2013 and 2012, respectively, and is included in capital credits from cooperatives.

NOTE 9—RELATED PARTIES (Continued)

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION: Investments in other associations includes a $26.7 and $41.6 million investment in CFC as of December 31, 2014 and 2013, respectively. At December 31, 2014 and 2013, the total outstanding debt owed by the Association to CFC was $196 and $116 million, respectively. The Association's share of CFC capital credit allocations was $637,000, $800,000 and $874,000 for 2014, 2013 and 2012, respectively, and is included in capital credits from cooperatives.

COBANK, ACB: Investments in other associations includes a $5.5 and $4.9 million investment in CoBank as of December 31, 2014 and 2013, respectively. At December 31, 2014 and 2013, the total outstanding debt owed by the Association to CoBank was $390 and $229 million, respectively. The Association's share of CoBank capital credit allocations was $2.3 million, $1.4 million and $794,000 for 2014, 2013 and 2012, respectively, and is included in capital credits from cooperatives.

WESTERN FUELS ASSOCIATION: WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which include the Association and BEPC. WFA supplies fuel to MBPP through contracts with coal companies and through its ownership in Western Fuels-Wyoming, which owns and operates the Dry Fork Mine. The Association also receives coal supplies directly from WFA for the Escalante Generating Station in New Mexico and spot coal for the Springerville Generating Station Unit 3 in Arizona. The Association's share of coal purchases from WFA was $74.7, $71.7 and $71.7 million in 2014, 2013 and 2012, respectively.

The Association advanced funds to WFA, through MBPP, for mine and equipment purchases and mine development costs. The fund advance balance of $1.4 million and $272,000 at December 31, 2014 and 2013, respectively, is included in investments in and advances to coal mines. The Association's membership interest in WFA totals $2.3 and $2.5 million at December 31, 2014 and 2013, respectively, and is included in investments in other associations. The Association's share of WFA capital credit allocations of $(177,000) for 2014, $1.2 million for 2013 and $0 for 2012 is included in capital credits from cooperatives.

TRAPPER MINING: The Association and certain participants in the Yampa Project own Trapper Mining. Organized as a cooperative, Trapper Mining supplied 35, 24 and 25 percent of the coal for the Yampa Project in 2014, 2013 and 2012, respectively. The Association's share of coal purchases from Trapper Mining was $30.6, $16.9 and $11.2 million in 2014, 2013 and 2012, respectively. The Association's membership interest in Trapper Mining of $13.7 and $13.2 million at December 31, 2014 and 2013, respectively, is included in investments in and advances to coal mines. The Association's share of Trapper Mining capital credit allocations of $532,000 in each of the years 2014, 2013 and 2012 is included in capital credits from cooperatives.

NOTE 10—EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLAN: Substantially all of the Association's 1,540 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 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.

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

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.

The Association's contributions to the RS Plan in each of the years 2014, 2013 and 2012 represented less than 5 percent of the total contributions made each year to the plan by all participating employers. The Association made contributions to the RS Plan of $21.5, $92.6 and $24.9 million in 2014, 2013 and 2012, respectively. Contributions in 2013 were significantly higher than those in 2014 and 2012 due to the Association's 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, the Association 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 Association's average age of its workforce from the Association's normal retirement age under the RS Plan.

The Association's contributions to the RS Plan include contributions for substantially all of the 362 bargaining unit employees that are made in accordance with collective bargaining agreements that will be in effect through April 3, 2016.

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, 2014, and over 80 percent funded at January 1, 2013, based on the Act funding target and the Act actuarial value of assets on those dates.

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

DEFINED CONTRIBUTION PLAN: The Association has 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. The Association makes no contributions for the 362 bargaining unit employees. For all of the eligible non-bargaining unit employees, other than the

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

216 employees of Colowyo Coal, the Association contributes 1 percent of an employee's eligible earnings. For the employees of Colowyo Coal, the Association contributes 7 percent of an employee's eligible earnings and also matches an employee's contributions up to 5 percent. The Association made contributions to the plan of $2.9, $2.9 and $3.0 million in 2014, 2013 and 2012, respectively.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: The Association sponsors three medical plans for all non-bargaining unit employees of the Association. 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, 2014, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

The postretirement medical benefit and postemployment medical benefit obligations are determined by an independent actuary and are included in accumulated postretirement benefit and postemployment obligations on the consolidated statements of financial position as follows (thousands):

	2014	2013
Postretirement medical benefit obligation at beginning of year	$2,957	$2,888
Service cost	582	134
Interest cost	256	136
Benefit payments	(276)	(201)
Actuarial loss	4,194	—
Postretirement medical benefit obligation at end of year	$7,713	$2,957
Postemployment medical benefit obligation at end of year	418	291
Total postretirement and postemployment medical obligations at end of year	$8,131	$3,248

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):

	2014	2013
Actuarial gain included in accumulated other comprehensive income at beginning of year	$ 3,081	$3,439
Reclassification adjustment included in income	31	(358)
Actuarial loss per actuarial study	(4,194)	—
Actuarial gain (loss) included in accumulated other comprehensive income at end of year	$(1,082)	$3,081

NOTE 10—EMPLOYEE BENEFIT PLANS (Continued)

The assumptions used in the 2014 actuarial study performed for the Association's postretirement medical benefit obligation were as follows:

Weighted-average discount rate	3.65%
Initial health care cost trend (2014)	8.00%
Ultimate health care cost trend	4.50%
Year that the rate reached the ultimate health care cost trend rate	2023
Expected return on plan assets (unfunded)	N/A
Average remaining service lives of active plan participants (years)	11.79

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	$685	$(600)
Net periodic postretirement medical benefit expense	$123	$(104)

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

2015	$ 355
2016	414
2017	481
2018	519
2019 and thereafter	3,729
	$5,498

NOTE 11—VARIABLE INTEREST ENTITIES

The following is a description of the Association's financial interests in variable interest entities that the Association considers significant. This includes an entity for which the Association is determined to be the primary beneficiary and therefore consolidates and also entities for which the Association is not the primary beneficiary and therefore does not consolidate.

Consolidated Variable Interest Entity:

Springerville Partnership: The Association owns a 51 percent equity interest, including the 1 percent general partner equity interest in the Springerville Partnership, which is the 100 percent owner of the Owner Lessor of the Springerville Generating Station Unit 3. The Association, as general partner, has 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 the Association's remittance of lease payments in order to permit the Owner Lessor, the holder of the Springerville Generating Station Unit 3 assets,

NOTE 11—VARIABLE INTEREST ENTITIES (Continued)

to pay the debt obligations and equity returns of the Springerville Partnership. The Association has the primary risk (expense) exposure in operating the Springerville Generating Station Unit 3 assets and is responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Generating Station 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 the Association was the primary beneficiary of the Owner Lessor. Therefore, the Springerville Partnership and Owner Lessor have been consolidated by the Association.

The Association's consolidated statements of financial position include the Springerville Partnership's net electric plant of $874.4 and $895.4 million at December 31, 2014 and 2013, respectively, the long-term debt of $548.1 and $583.3 million at December 31, 2014 and 2013, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $109.3 and $110.7 million at December 31, 2014 and 2013, respectively.

The Association's consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $21.0 million for both 2014 and 2013 and interest expense of $34.1 and $35.9 million for 2014 and 2013, respectively. The net losses attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership are reflected on the Association's 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 not-for-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which includes the Association. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in Western Fuels-Wyoming. The Association also receives coal supplies directly from WFA for the Escalante Generating Station in New Mexico and spot coal for the Springerville Generating Station 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 the Association has 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, the Association is not the primary beneficiary of WFA and the entity is not consolidated. The Association's investment in WFA, accounted for using the cost method, was $2.3 million at December 31, 2014 and is included in investments in other associations (see Note 2—Investments in Other Associations and Note 9—Western Fuels Association).

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 Generating Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by BEPC). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the

NOTE 11—VARIABLE INTEREST ENTITIES (Continued)

participants of MBPP own the remaining 25 percent of class BB shares of WFW (of which the Association has a 24.1 percent undivided interest). 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 the Association has 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, the Association is 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 Generating Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by the participants of the Yampa Project (the owners of the Craig Generating Station Units 1 and 2), of which the Association has a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There isn't sufficient equity at risk for Trapper Mining to finance its activities without the additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which the Association has 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, the Association is not the primary beneficiary of Trapper Mining and the entity is not consolidated. The Association records its investment in Trapper Mining using the cost method. The Association's membership interest in Trapper Mining was $13.7 million at December 31, 2014 (see Note 2—Investments In and Advances To Coal Mines and Note 9—Trapper Mining).

NOTE 12—COMMITMENTS AND CONTINGENCIES

SALES: The Association has 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. The Association also has (1) a resource-contingent firm power sales contract of 100 megawatts to Salt River Project through August 31, 2036, (2) a firm power sales contract committing up to 13 megawatts to BEPC through 2025 and (3) a resource-contingent firm power sales contract with PacifiCorp committing 25 megawatts through 2020.

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

COAL PURCHASE REQUIREMENTS: The Association is committed to purchase coal for its generating plants under long-term contracts that expire between 2017 and 2034. These contracts require the Association 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, 2014, the annual minimum coal purchases under these contracts are as follows (thousands):

2015	$101,266
2016	103,760
2017	106,790
2018	103,390
2019	104,686
Thereafter	145,212
	$665,104

ELECTRIC POWER PURCHASE AGREEMENTS: The Association's 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 the Association 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). The Association is currently working to enter into a new contract relating to the Loveland Area Project which will run through September 2054. The Association also expects to enter into two new contracts related to Salt Lake City Area Integrated Projects which will extend the term of those existing contracts.

The Association's 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. The Association utilizes a portion of its electric purchases from Basin to supply power to the Association's 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. The Association has 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.

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

	2014	2013	2012
WAPA	$ 91,639	$ 91,038	$ 87,122
Basin	132,649	136,223	137,853

ENVIRONMENTAL: The Association's electric generation facilities are subject to various operating permits and must operate within guidelines imposed by numerous environmental regulations.

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

The Association believes these facilities are currently in compliance with such regulatory and operating permit requirements.

LEGAL: On October 19, 2012, the Association gave notice, as required by New Mexico statutes, to the New Mexico Public Regulation Commission ("NMPRC") of its new A-37 wholesale rate which was scheduled to become effective on January 1, 2013. The rate would have increased revenue collected from the Association's 44 member systems by approximately 4.9 percent and from its 12 New Mexico member systems by approximately 6.7 percent. In November 2012, three of the Association's member systems located in New Mexico filed protests of the Association's 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 statutes. Also, on January 25, 2013, the Association 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. The Association intends to pursue rate recovery and its federal challenge to the actions of the NMPRC. On January 25, 2013, the Association made an additional filing at the NMPRC seeking interim rate recovery from its New Mexico member systems during the pendency of the NMPRC proceedings on the original rate filing. The NMPRC denied the filing on March 13, 2013. The Association appealed that denial to the New Mexico Supreme Court. A decision by the Court is pending. On June 25, 2013, the Association filed to withdraw the A-37 rate. On July 3, 2013, the NMPRC denied the filing to withdraw and subsequently ordered the A-37 rate filing to be consolidated with the A-38 rate filing described below. On September 10, 2013, the Association gave notice, as required by New Mexico statutes, to the NMPRC of its 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, the Association and the New Mexico member systems 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. The Association filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider is applied in conjunction with the 2012 wholesale rate to recover additional revenue from the New Mexico member systems in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. In 2014 and 2013, the overall impact of the New Mexico member systems paying a lower rate was approximately $16.4 million and $15.6 million, respectively. As part of the global settlement, the parties seek to establish a permanent wholesale rate going forward, address the issue of our rate regulation in New Mexico, evaluate the payment of capital credits, evaluate the buyout methodology for member systems and perform a cost of service study. The Association cannot predict the outcome of this matter or if a global settlement will be reached, although the Association does not believe this proceeding is likely to have a material adverse effect on the Association's financial condition, future results of operations or cash flows.

On March 4, 2013, three of the Association's Colorado member systems and several of their large industrial customers filed a complaint at the Colorado Public Utilities Commission ("COPUC") alleging that the A-37 rate design was unjust and unreasonable. On April 4, 2013, the Association filed a motion to dismiss the complaint arguing lack of jurisdiction by the COPUC over the Association's

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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 the Association, who has been historically regulated by its membership through its Board of Directors, 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 the Association's motion to dismiss. In October 2013, the Association appealed the ALJ's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part the Association's motion contesting the ALJ's decision and remanded the case to the ALJ to hold a hearing on limited issues. In November 2014, the Association and three Colorado member systems executed a preliminary agreement providing for a temporary rate rider effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico member systems 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. The Association cannot predict the outcome of this matter or if a global settlement will be reached, although the Association does not believe this proceeding is likely to have a material adverse effect on the Association's financial condition, future results of operations or cash flows.

The Purchase Option and Development Agreement was executed on July 26, 2007 between the Association and Sunflower Electric Power Corporation ("Sunflower") and other Sunflower parties. The agreement calls for the Association 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 the Association, Sunflower and the other parties to the Purchase Option and Development Agreement after the Association exercises its 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 the Association and Sunflower appealed the denial to the Kansas courts. Subsequent to the denial of the air permit, Sunflower entered into an agreement with the governor of Kansas that could result in the KDHE issuing a permit for one new coal-fired generating unit at Holcomb Station of 895 megawatts. As a result of the agreement, Sunflower and the Association withdrew their 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. Excluding the cost of land and water rights, the cost of developing the units incurred by the Association as of December 31, 2014 is $82.0 million, which is included in other deferred charges on the consolidated statements of financial position. The Association is unable to project the ultimate outcome of this matter or when the air permit application process may conclude.

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

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, have filed separate lawsuits against the Association's member system, Jemez Mountains Electric Cooperative, Inc. ("JMEC") in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs allege 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 court allowed all parties and related parties to amend their complaints to include the addition of the Association as a party defendant. The allegations in each case are similar. Plaintiffs allege that the Association owed them independent duties to inspect and maintain the right of way for JMEC's distribution line and that the Association is also jointly liable for any negligence by JMEC under "joint venture" and alter ego theories. On December 29, 2014, a demand letter was received from the U.S. Department of Justice for costs incurred as a result of the fire, alleging the "joint venture" theory. JMEC settled with the subrogated insurers, executing and funding the deal on December 30, 2014. On February 7, 2015, the court dismissed the subrogated insurers' claims against the Association with prejudice. Settlement demands have been received from two plaintiffs 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. In conjunction with the demands, the two plaintiffs have requested mediation. Trial is currently set for three weeks commencing May 2, 2015. The Association maintains $100 million in liability insurance coverage for this matter. Although the Association cannot predict the outcome of these matters at this point in time, the Association intends to vigorously defend these matters and does not expect them to have a material adverse effect on the Association's financial condition, future results of operations or cash flows.

In February 2013, WildEarth Guardians ("WEG") filed suit against the United States Office of Surface Mining, Reclamation and Enforcement ("OSM") in the United States District Court for the District of Colorado, alleging OSM's failure to involve the public and address the economic impacts of coal mining throughout the Rocky Mountain West prior to mine plan approval. The suit alleges unlawful mine plan approval of mines located in Colorado, Montana, New Mexico and Wyoming. The court granted intervention to several mine owners, including Colowyo Coal and Trapper Mining, of which the Association is a member. The Colowyo Mine plan in WEG's suit was approved in 2007. In February 2014, the court agreed to sever the claims and transfer venue for the mines located outside of Colorado. In August 2014, WEG submitted its opening brief on the part of the case that remains in Colorado as Civil Action No. 1:13-cv-00518-JLK. OSM's responsive brief was filed on October 7, 2014, and Trapper Mining and Colowyo Coal, as interveners, each filed a responsive brief on October 20, 2014. WEG has asked the court to declare that OSM's approval of the mine plans violated the National Environmental Policy Act and for the court to vacate the approvals until OSM demonstrates compliance with the act. Federal respondents and respondent-interveners have requested oral argument. Because of the early nature of the proceedings, the Association is unable to project the outcome of this matter although the Association does not believe it is likely to have a material adverse effect on the Association's financial condition, future results of operations or cash flows.

On October 19, 2004, WFA and BEPC filed a complaint with the STB alleging that the shipping rates instituted by BNSF for the transportation of coal to the Laramie River Generating Station were unreasonably high and asked the STB to set reasonable rates. On July 27, 2009, the STB issued its final decision, upholding the complaint and ordering refunds and shipping rate reductions to WFA and

NOTE 12—COMMITMENTS AND CONTINGENCIES (Continued)

BEPC. On September 2, 2009, BNSF appealed the STB decision to the United States Court of Appeals for the DC Circuit. Notwithstanding the appeal, BNSF refunded certain amounts and reduced shipping rates. Those reductions were passed on to WFA's and BEPC's members, including the Association. However, those reductions were subject to refund in the event BNSF is ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, the Association did not recognize the benefit of the receipt of $29.4 million in 2009 in the consolidated statements of operations and still has not as of December 31, 2014. Instead, the $29.4 million was recorded as a liability and is included in other deferred credits and other liabilities as of December 31, 2014, 2013 and 2012. On May 11, 2010, the Court of Appeals decided two of the three issues in favor of WFA and BECP. On the third issue, the Court of Appeals remanded the decision back to the STB directing the STB to explain in greater detail why its methodology for allocating variable costs did not double count certain revenue. On June 15, 2012, the STB provided the detailed recommendation on its allocation and affirmed its earlier decision, and BNSF subsequently appealed the STB decision to the Court of Appeals. On January 31, 2014, the Court of Appeals remanded the case back to the STB noting that the STB, under the previous remand, should have also considered whether to apply alternative average total cost to the allocation or provided a reasonable explanation for its actions. On January 28, 2015, BNSF, WFA and BEPC filed a joint petition at the STB asking the STB to hold the remanded case in abeyance. In this filing, the parties informed the STB that they had reached a preliminary settlement agreement that called for the dismissal of the case. The parties also informed the STB that the preliminary agreement was contingent upon the parties' development and execution of a rail transportation contract.

On February 9, 2015, Delta-Montrose Electric Association ("DMEA"), a member of the Association, filed a petition for declaratory order with the Federal Energy Regulatory Commission ("FERC") seeking a declaratory order from FERC finding that its wholesale power contract with the Association is subject to FERC jurisdiction because the Association has paid off all RUS debt and is now a FERC jurisdictional public utility; that the wholesale power contract cannot be read to preclude DMEA from purchasing power from a "qualifying resource" pursuant to the provisions of the Public Utilities Regulatory Policy Act ("PURPA") and FERC regulations thereunder; and that DMEA has the right under FERC's PURPA regulations to negotiate its purchase power price from a "qualifying resource" and to reduce its purchases from the Association by that amount. Comments are due related to such petition on March 11, 2015. Because of the early nature of the proceedings, the Association is unable to project the outcome of this matter although the Association does not believe it is likely to have a material adverse effect on the Association's financial condition, future results of operations or cash flows.

Tri-State Generation and Transmission Association, Inc.

Consolidated Statements of Financial Position (unaudited)

(dollars in thousands)

	March 31, 2015	December 31, 2014
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,228,254	$ 5,193,236
Construction work in progress	230,771	206,097
Total electric plant	5,459,025	5,399,333
Less allowances for depreciation and amortization	(2,155,101)	(2,129,173)
Net electric plant	3,303,924	3,270,160
Other plant	221,531	210,694
Accumulated depreciation and depletion	(61,592)	(58,117)
Net other plant	159,939	152,577
Total property, plant and equipment	3,483,863	3,422,737
Other assets and investments		
Investments in other associations	118,672	117,976
Investments in and advances to coal mines	16,738	15,016
Restricted cash and investments	39,333	39,376
Intangible assets	31,127	32,958
Other noncurrent assets	12,549	12,531
Total other assets and investments	218,419	217,857
Current assets		
Cash and cash equivalents	77,150	92,468
Restricted cash and investments	9,806	9,784
Deposits and advances	28,094	22,224
Accounts receivable—Members	85,839	105,723
Other accounts receivable	26,917	25,693
Coal inventory	50,179	40,673
Materials and supplies	82,901	80,069
Total current assets	360,886	376,634
Deferred charges		
Regulatory assets	429,954	426.043
Prepayment—NRECA Retirement and Security Plan	53,285	54,665
Other	189,377	178,454
Total deferred charges	672,616	659,162
Total assets	**$ 4,715,784**	**$ 4,676,390**

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

Tri-State Generation and Transmission Association, Inc.

Consolidated Statements of Financial Position (unaudited) (Continued)

(dollars in thousands)

	March 31, 2015	December 31, 2014
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 928,795	$ 908,669
Accumulated other comprehensive income (loss)	(835)	(828)
Noncontrolling interest	109,122	109,302
Total equity	1,037,082	1,017,143
Long-term debt	3,144,148	3,165,960
Total capitalization	4,181,230	4,183,103
Current liabilities		
Member advances	11,290	14,576
Accounts payable	121,218	103,177
Accrued expenses	24,255	30,005
Accrued interest	47,636	32,517
Accrued property taxes	24,942	26,010
Current maturities of long-term debt	96,963	94,342
Total current liabilities	326,304	300,627
Deferred credits and other liabilities		
Regulatory liabilities	45,000	45,000
Deferred income tax liability	27,625	17,230
Intangible liabilities	8,609	9,424
Asset retirement obligations	53,544	53,754
Other	65,220	59,121
Total deferred credits and other liabilities	199,998	184,529
Accumulated postretirement benefit and postemployment obligations	8,252	8,131
Total equity and liabilities	**$4,715,784**	**$4,676,390**

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,	
	2015	2014
Operating Revenues		
Member electric sales	$267,539	$264,594
Non-member electric sales	35,063	59,461
Other	25,789	25,143
	328,391	349,198
Operating expenses		
Purchased power	73,137	78,929
Fuel	61,275	73,916
Production	53,520	53,013
Transmission	37,099	35,754
General and administrative	6,151	6,197
Depreciation and amortization	34,978	30,897
Coal mining	8,827	12,484
Other	4,020	4,356
	279,007	295,546
Operating margins	**49,384**	**53,652**
Other income		
Interest Income	1,083	3,261
Capital credits from cooperatives	4,294	1,670
Other income	1,348	1,269
	6,725	6,200
Interest expense, net of amounts capitalized	36,163	35,742
Income taxes	—	—
Net margins including noncontrolling interest	19,946	24,110
Net loss attributable to noncontrolling interest	180	401
Net margins attributable to the Association	**$ 20,126**	**$ 24,511**

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,	
	2015	**2014**
Net margins including noncontrolling interest	$19,946	$24,110
Other comprehensive income (loss):		
Unrealized loss on securities available for sale	(16)	(25)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	9	(93)
Income tax expense related to components of other comprehensive loss	—	—
Other comprehensive income (loss)	(7)	(118)
Comprehensive income including noncontrolling interest	19,939	23,993
Net comprehensive loss attributable to noncontrolling interest	180	401
Comprehensive income attributable to the Association	**$20,119**	**$24,393**

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,	
	2015	2014
Patronage capital equity at beginning of period	$ 908,669	$865,379
Net margins attributable to the Association	20,126	24,511
Retirement of patronage capital	—	(10,000)
Patronage capital equity at end of period	**928,795**	**879,890**
Accumulated other comprehensive income (loss) at beginning of period	(828)	3,335
Unrealized loss on securities available for sale	(16)	(25)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	9	(93)
Accumulated other comprehensive income (loss) at end of period	**(835)**	**3,217**
Noncontrolling interest at beginning of period	109,302	110,740
Net loss attributable to noncontrolling interest	(180)	(401)
Equity distribution to noncontrolling interest		—
Noncontrolling interest at end of period	**109,122**	**110,339**
Total equity at end of period	**$1,037,082**	**$993,446**

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, 2015	Three Months Ended March 31, 2014
Operating activities		
Net margins including noncontrolling interest	$ 19,946	$ 24,110
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation and amortization	34,978	29,796
Amortization of intangible asset	1,831	1,831
Amortization of NRECA Retirement and Security Plan prepayment	1,380	1,380
Amortization of debt issuance costs	465	232
Capital credit allocations from cooperatives and income from coal mines under (over) refund distributions	(2,673)	968
Recognition of deferred revenue	—	(5,000)
Changes in operating assets and liabilities:		
Accounts receivable	18,660	5,078
Coal inventory	(9,506)	10,312
Materials and supplies	(2,832)	(2,991)
Accounts payable and accrued expenses	12,414	(12,702)
Accrued interest	15,119	1,069
Accrued property taxes	(1,068)	(293)
Other	(1,617)	(4,937)
Net cash provided by operating activities	**87,097**	**48,624**
Investing activities		
Purchases of plant	(69,788)	(37,008)
Changes in deferred charges	(6,912)	(5,523)
Proceeds from other investments	413	1,866
Net cash used in investing activities	**(76,287)**	**(40,665)**
Financing activities		
Member advances	(3,286)	(1,077)
Payments of long-term debt	(58,283)	(89,372)
Proceeds from issuance of debt	39,654	—
Decrease in advance payments to RUS	—	7,780
Retirement of patronage capital	(4,213)	(13,849)
Net cash used in financing activities	**(26,128)**	**(96,518)**
Net decrease in cash and cash equivalents	**(15,318)**	**(88,559)**
Cash and cash equivalents—beginning	**92,468**	**193,057**
Cash and cash equivalents—ending	**$ 77,150**	**$104,498**
Supplemental cash flow information:		
Cash paid for interest	$ 24,132	$ 38,569
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ 4,644	$ (2,173)

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

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 for interim financial information and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U.S. generally accepted accounting principles ("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 2014 Annual Report. 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 three months ended March 31, 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 ("BEPC")) 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, 2015 (thousands):

	Tri-State share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project—Craig Station Units 1 and 2	24.00%	$345,362	$230,779	$11,483
MBPP—Laramie River Station	24.13%	388,009	289,842	7,636
San Juan Project—San Juan Unit 3	8.20%	73,501	56,416	10,208
Total		$806,872	$577,037	$29,327

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

NOTE 2—ACCOUNTING FOR RATE REGULATION (Continued)

our Board of Directors, 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 Members through rates approved by our Board of Directors 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 of Directors in accordance with our rate policy.

Regulatory assets and liabilities are as follows (thousands):

	March 31, 2015	December 31, 2014
Regulatory assets		
Deferred income tax expense(1)	$ 27,625	$ 17,230
Deferred prepaid lease expense—Craig 3 Lease(2)	21,038	22,656
Deferred prepaid lease expense—Springerville 3 Lease(3)	94,595	95,168
Goodwill—J.M. Shafer(4)	62,678	63,390
Goodwill—Colowyo Coal(5)	42,102	43,526
Deferred debt prepayment transaction costs(6)	181,916	184,073
	429,954	426,043
Regulatory liabilities		
Deferred revenues(7)	45,000	45,000
Net regulatory asset	$384,954	$381,043

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

(2) Deferral of loss on acquisition related to the Craig Generating Station 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 into expense each year through the remaining original life of the lease ending in 2018.

(3) Deferral of loss on acquisition related to the Springerville Generating Station Unit 3 prepaid lease expense upon the 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 into expense beginning in 2009 through the remaining life of Springerville Generating Station Unit 3 ending in 2056.

(4) Represents goodwill related to the acquisition of Thermo Cogeneration Partnership, LP in December 2011. Goodwill is being amortized to expense over the 25-year remaining life of the J.M. Shafer Generating Station and recovered in rates.

(5) Represents goodwill related to our acquisition of Colowyo Coal Company LP (“Colowyo Coal”) in December 2011. Goodwill is being amortized to expense over the 44-year remaining life of the Craig Generating Station since the coal mine was acquired primarily for its use and recovered in rates.

NOTE 2—ACCOUNTING FOR RATE REGULATION (Continued)

(6) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized into interest expense over the 21.4-year average life of the new debt issued.

(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 include our investment in the patronage capital of other cooperatives and these investments are accounted for using the cost method. 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. Patronage credits allocated to us totaled $3.1 million for the three months ended March 31, 2015 and $2.7 million for the comparable period in 2014.

NOTE 4—RESTRICTED CASH AND INVESTMENTS

Restricted cash and investments represent funds designated by our Board of Directors 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 is therefore a current asset on the statements of financial position. The other funds are noncurrent and are included in other assets and investments.

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. A portion of the defeasance investment is for Colowyo Bond debt payments within one year and is, therefore, a current asset on the consolidated statements of financial position. The remainder of the investment is noncurrent.

We received $29.4 million in 2009 from the 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 are subject to refund in the event BNSF is ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize the benefit of the receipt of the $29.4 million in 2009 in the consolidated statements of operations and still have not as of March 31, 2015. See Note 11—Legal. These funds were designated by our Board of Directors to be held as restricted cash.

NOTE 4—RESTRICTED CASH AND INVESTMENTS (Continued)

Restricted cash and investments are as follows (thousands):

	March 31, 2015	December 31, 2014
Investments in securities pledged as collateral	$ 9,144	$ 9,192
Funds restricted by contract	662	592
Restricted cash and investments—current	9,806	9,784
BNSF settlement	29,381	29,381
Funds restricted by contract	1,000	1,000
Investments in securities pledged as collateral	8,952	8,995
Restricted cash and investments—noncurrent	39,333	39,376
Total restricted cash and investments	$49,139	$49,160

NOTE 5—OTHER DEFERRED CHARGES

We make expenditures for preliminary surveys, plans 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 may be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered in rates subject to approval by our Board of Directors, which has budgetary and rate-setting authority. As of March 31, 2015, preliminary survey and investigation was primarily comprised of expenditures for the Holcomb Station Project of $83.1 million and $27.6 million for a transmission project located in eastern Colorado known as the Eastern Plains Transmission Project.

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

We account for debt issuance costs as deferred debt expense. Deferred debt expense is amortized to expense using an effective interest method over the life of the respective debt issuance.

During 2014, we refinanced a significant portion of our long-term debt. Debt issuance costs of $13.0 million were incurred as a result of this refinancing. These debt issuance costs are included in other deferred charges and are being amortized to expense using an effective interest method over the weighted average life of the respective debt issuances.

Other deferred charges are as follows (thousands):

	March 31, 2015	December 31, 2014
Preliminary surveys, plans and investigation	$133,612	$131,693
Advances to operating agents of jointly owned facilities	27,479	20,567
Debt issuance costs	22,135	22,254
Other	6,151	3,940
Total other deferred charges	$189,377	$178,454

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 one unsecured note. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Generating Station Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance discussed later in this note and an unconditional guarantee by us. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement and an equity to capitalization ratio requirement.

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

	March 31, 2015	December 31, 2014
Total debt	$3,241,111	$3,260,302
Less current maturities	(96,963)	(94,342)
Long-term debt	$3,144,148	$3,165,960

NOTE 7—OTHER DEFERRED CREDITS AND OTHER LIABILITIES

We received $29.4 million in 2009 from the BNSF as a reduction of prior coal delivery shipping charges as the result of the decision of the STB. However, BNSF appealed the decision. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize the benefit of the receipt of the $29.4 million in 2009 in the consolidated statements of operations and still have not as of March 31, 2015. See Note 11—Legal.

We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits. We have received upfront payments from others for the use of optical fiber and these are reflected in unearned revenue until recognized over the life of the agreement.

Other deferred credits and other liabilities are as follows (thousands):

	March 31, 2015	December 31, 2014
BNSF rate settlement proceeds not recognized in income	$29,381	$29,381
Customer deposits	4,538	2,464
Unearned revenue	4,127	4,210
Other deferred credits	27,174	23,066
Total other deferred credits and other liabilities	$65,220	$59,121

NOTE 8—INCOME TAXES

We are a non-exempt cooperative subject to federal and state taxation and, as a cooperative, is 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. We had no income tax expense or benefit for the three months ended March 31, 2015 and 2014.

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 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 are 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:

	As of March 31, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Marketable securities	$937	$1,175	$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 March 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.

NOTE 9—FAIR VALUE (Continued)

Long-Term Debt

The fair values of long-term 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 long-term debt are as follows:

	As of March 31, 2015		As of December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$3,241,111	$3,735,192	$3,260,302	$3,716,513

We did not have any financial assets or liabilities measured at fair value on a recurring basis that are included in the Level 3 fair value category.

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 Generating Station 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 Generating Station 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 Generating Station Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Generating Station 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 $869.1 and $874.4 million at March 31, 2015 and December 31, 2014, respectively, the long-term debt of $512.7 and $548.1 million at March 31, 2015 and December 31, 2014, respectively, accrued interest associated with the long-term debt of $5.7 million and $15.2 million at March 31, 2015 and December 31, 2014, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $109.1 and $109.3 million at March 31, 2015 and December 31, 2014, respectively.

NOTE 10—VARIABLE INTEREST ENTITIES (Continued)

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, 2015 and the comparable period in 2014. Our consolidated statements of operations also include interest expense of $8.2 for the three months ended March 31, 2015 and $8.6 million for the comparable period in 2014. 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"): WFA is a not-for-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 Generating Station 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 $2.3 million at March 31, 2015 and December 31, 2014, 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 Generating Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by BEPC). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP own the remaining 25 percent of class BB shares of WFW (of which we have a 24.1 percent undivided interest). 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.

NOTE 10—VARIABLE INTEREST ENTITIES (Continued)

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 the participants of the Yampa Project (the owners of the Craig Generating Station Units 1 and 2), of which we have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There isn’t sufficient equity at risk for Trapper Mining to finance its activities without 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 cost method. Our membership interest in Trapper Mining was $14.8 million at March 31, 2015 and $13.7 million at December 31, 2014.

NOTE 11—LEGAL

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 the option to acquire the development rights. The purchase date cannot currently be estimated due to legal uncertainties surrounding the status of the necessary air permits. The original air permit application was denied by the Kansas Department of Health and Environment (“KDHE”) in October 2007 and we and Sunflower appealed the denial to the Kansas courts. Subsequent to the denial of the air permit, Sunflower entered into an agreement with the governor of Kansas that could result in the KDHE issuing a permit for one new coal-fired generating unit at Holcomb Station of 895 megawatts. As a result of the agreement, we and Sunflower 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. Excluding the cost of land and water rights, the cost of developing the units incurred by us as of March 31, 2015 is $83.1 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.

NOTE 11—LEGAL (Continued)

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 our 44 Members by approximately 4.9 percent and from our 12 New Mexico Members 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 is 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 2013 and 2014, the overall impact of the New Mexico Members paying a lower rate was approximately $15.6 million and $16.4 million, respectively. For the three months ended March 31, 2015, the overall impact of the New Mexico Members paying a lower rate was approximately $1.9 million. As part of the global settlement, the parties seek to establish a wholesale rate going forward, address the issue of our rate regulation in New Mexico, evaluate the payment of capital credits, evaluate the buyout methodology for Members and perform a cost of service study. 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. The judge bifurcated the case into deciding first, whether the COPUC had the jurisdiction to hear such a case against us, who has been historically regulated by its membership through its Board of Directors, and secondly to hear the facts in the case depending on

NOTE 11—LEGAL (Continued)

jurisdiction. The administrative law judge conducted a hearing in July 2013 and ruled on September 11, 2013 denying our motion to dismiss. In October 2013, we appealed the administrative law judge's decision to the full commission and on December 18, 2013, the commission granted in part and denied in part our motion contesting the administrative law judge's decision and remanded the case to the administrative law judge to hold a hearing on limited issues. In November 2014, we and the three Colorado Members executed a preliminary agreement providing for a temporary optional rate effective December 1, 2014 and to continue through no later than December 31, 2015, available to all non-New Mexico Members and a suspension of the procedural schedule related to the complaint. The administrative law judge entered a decision on November 28, 2014 holding this matter in abeyance until December 31, 2015 to give the parties time to work toward a global settlement and permanent rate. 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 February 9, 2015, Delta-Montrose Electric Association ("DMEA") filed a Petition For Declaratory Order with the United States Federal Energy Regulatory Commission ("FERC") seeking a declaratory order from FERC finding that its wholesale electric service contract with us is subject to FERC jurisdiction because we have paid off all our Rural Utilities Service ("RUS") debt; that the wholesale electric service contract cannot be read to preclude DMEA from purchasing power from a "qualifying resource" pursuant to the provisions of PURPA and FERC regulations thereunder; and that DMEA has the right under FERC's PURPA regulations to negotiate its purchase power price from a "qualifying resource" and to reduce its purchases from us by that amount even if that amount exceeds its contractual obligation to purchase from us. We filed our motion to intervene and protest with FERC related to such petition on March 11, 2015. DMEA filed a motion to answer and answer to our protest on March 26, 2015. We filed a motion for leave to answer and answer to DEMA's answer on April 2, 2015. 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.

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 allege 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 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 are similar. Plaintiffs allege that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we

NOTE 11—LEGAL (Continued)

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 court dismissed the subrogated insurers' claims against us with prejudice. Settlement demands have been 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. In conjunction with the demands, the two plaintiffs have requested mediation. On March 9, 2015, the 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. Trial is currently scheduled to commence in September 2015. 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 intend to vigorously defend these matters and do not expect them to have a material adverse effect on our financial condition or our future results of operations or cash flows.

We are involved in two separate water rights proceedings in the State of New Mexico that can 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 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.

In February 2013, WildEarth Guardians ("WEG"), filed suit against the United States Office of Surface Mining, Reclamation and Enforcement ("OSM"), in the United States District Court for the District of Colorado, alleging OSM's failure to involve the public and address the economic impacts of coal mining throughout the Rocky Mountain West prior to mine plan approval. The suit alleged unlawful mine plan approval of mines located in Colorado, Montana, New Mexico, and Wyoming. The court granted intervention to several mine owners, including Colowyo Coal and Trapper Mining. The Colowyo Mine plan in WEG's suit was approved in 2007 and the Trapper Mine plan in WEG's suit was approved in 2009. In February 2014, the court agreed to sever the claims and transfer venue for the mines located outside of Colorado. In August 2014, WEG submitted its opening brief on the part of the case that remained in Colorado as Civil Action No. 1:13-cv-00518-RBJ. OSM's responsive brief was filed on October 7, 2014, and Trapper Mining and Colowyo Coal, as intervenors, each filed a responsive brief on October 20, 2014. WEG has asked the court to declare that OSM's approval of the mine plans violated the National Environmental Policy Act ("NEPA") and for the court to vacate the approvals until OSM demonstrates compliance with the act. Oral arguments took place on April 24, 2015. On May 8, 2015, the court issued an order agreeing with WEG that OSM's approval of the mine plans violated NEPA. The court noted that the majority of the coal covered by the permit at Trapper Mine had already been mined, but ordered that no remaining coal covered by the permit be mined

NOTE 11—LEGAL (Continued)

prior to approval of a new permit revision. With respect to the Colowyo Mine, the court determined that immediate vacatur of the Colowyo Mine plan did not outweigh the potential harm. The court defered an immediate vacatur order for a period of 120 days from May 8, 2015 and expected the OSM during that time to address the deficiencies in the permitting process. Colowyo Coal is working with OSM to respond to the court's order within the 120 days and OSM has undertaken efforts to respond to the court's order within the 120 days. On May 29, 2015, Colowyo Coal filed a Notice of Appeal and Motion to Stay the Order issued by the court. In the event the OSM does not respond to the court's order within the120 days and the court enters a vacatur order, we are evaluating our options as to alternatives.

On October 19, 2004, WFA and BEPC filed a complaint with the STB alleging that the shipping rates instituted by the BNSF for the delivery of coal to the Laramie River Generating Station were unjust and unreasonable. On July 27, 2009, the STB issued its final decision, upholding the complaint and ordering refunds and shipping rate reductions to WFA and BEPC. On September 2, 2009, BNSF appealed the STB decision to the United States Court of Appeals for the DC Circuit. Notwithstanding the appeal, BNSF refunded certain amounts and reduced shipping rates. Those reductions were passed on to WFA's and BEPC's members, including us. However, those reductions were subject to refund in the event BNSF was ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize the benefit of the receipt of $29.4 million in 2009 in the consolidated statements of operations and have not as of March 31, 2015. Instead, the $29.4 million was recorded as a liability and is included in deferred credits and other liabilities as of March 31, 2015, December 31, 2014 and 2013. On May 11, 2010, the Court of Appeals decided two of the three issues in favor of WFA and BEPC. On the third issue, the Court of Appeals remanded the decision back to the STB directing the STB to explain in greater detail why its methodology for allocating variable costs did not double count certain revenue. On June 15, 2012, the STB provided the detailed recommendation on its allocation and affirmed its earlier decision, and BNSF subsequently appealed the STB decision to the Court of Appeals. On January 31, 2014, the Court of Appeals remanded the case back to the STB noting that the STB, under the previous remand, should have also considered whether to apply alternative average total cost to the allocation or provided a reasonable explanation for its actions. On January 28, 2015, BNSF, WFA and BEPC filed a joint petition at the STB asking the STB to hold the remanded case in abeyance. In this filing, the parties informed the STB that they had reached a preliminary settlement agreement that called for the dismissal of the case. The parties also informed the STB that the preliminary agreement was contingent upon the parties' development and execution of a rail transportation contract. On May 15, 2015, BNSF, WFA and BEPC filed a joint petition at the STB informing the STB that the parties have entered into a rail transportation agreement settling all matters at issue in the proceeding and asking the STB to vacate the rate prescription it entered in the proceeding in 2009, to dismiss the complaint with prejudice, and to discontinue the proceeding. On June 12, 2015, the STB granted the joint petition.

NOTE 12—NEW ACCOUNTING PRONOUNCEMENTS

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-03, *Interest-Imputation of Interest (Subtopic 835-30), Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt consistent with debt discounts. The recognition and measurement for debt issuance

NOTE 12—NEW ACCOUNTING PRONOUNCEMENTS (Continued)

costs are not affected by the amendments in this ASU. For public business entities, ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is allowed for all entities for financial statements that have not been previously issued. We are currently considering the impact of this amendment on our financial position and 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. For public business entities, ASU 2015-02 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 are currently considering the impact of this amendment on our financial position and results of operations.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. This amendment replaces current revenue guidance, based on risks and rewards, with a transfer of control model. The core principle under this new model states that revenue should be recognized to depict the transfer of promised 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, ASU 2014-09 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. ASU 2014-09 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. ASU 2014-09 is effective for the fiscal year beginning January 1, 2017 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). Early adoption is not permitted. On April 1, 2015, the FASB proposed deferring the effective date by one year. Under the proposal the standard would be effective for annual reporting periods beginning after December 15, 2017. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. We are currently evaluating the impact of this amendment on our financial position and results of operations.

TRI-STATE

Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative

Until , 2015, 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.
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc.
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

Exhibit Number	Description
4.2†	Exchange and Registration Rights Agreement, dated October 30, 2014, between Tri-State Generation and Transmission Association, Inc. and Goldman, Sachs & Co.
4.3†	Form of Exchange Bond for 3.70% First Mortgage Bonds, Series 2014E-1, due 2024
4.4†	Form of Exchange Bond for 4.70% First Mortgage Bonds, Series 2014E-2, due 2044
4.5.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.5.2*	Secured Promissory Note, dated January 10, 1989, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9028, in the original principal amount of $1,969,377
4.6.1*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.6.2*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9034, in the original principal amount of $10,426,435.24
4.6.3*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9035, in the original principal amount of $38,220,475.57
4.6.4*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9038, in the original principal amount of $943,092.72
4.6.5*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9039, in the original principal amount of $821,815.11
4.6.6*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9040, in the original principal amount of $32,224,821
4.7.1*	Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.7.2*	First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997
4.7.3*	Secured Promissory Note, dated March 14, 1997, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9044, in the original amount of $15,600,000
4.7.4*	Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.7.5*	Secured Promissory Note, dated January 26, 1999, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9046, in the original amount of $1,172,665.68
4.8.1*	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

Exhibit Number	Description
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
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

Exhibit Number	Description
4.19.1*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000
4.19.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000
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
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
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
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
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
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
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
10.7†	Series 2009C Note Purchase Agreement, dated as of April 8, 2009, between Tri-State and various purchasers of the notes identified therein
10.8†	2014 Note Purchase Agreement, dated as of October 31, 2014, between Tri-State and various purchasers of the notes identified therein

Exhibit Number	Description
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
10.10**†	Director Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008
10.11**†	Retention Agreement for Joel K. Bladow, effective as of April 30, 2014, between Tri-State and Joel K. Bladow
10.12**†	Retention Agreement for Patrick L. Bridges, effective as of April 30, 2014, between Tri-State and Patrick L. Bridges
10.13**†	Retention Agreement for Jennifer Godin Goss, effective as of April 30, 2014, between Tri-State and Jennifer Godin Goss
10.14**†	Retention Agreement for Bradford C. Nebergall, effective as of April 30, 2014, between Tri-State and Bradford C. Nebergall
10.15**†	Retention Agreement for John O' Flannigan, effective as of April 30, 2014, between Tri-State and John O' Flannigan
10.16**†	Retention Agreement for Kenneth V. Reif, effective as of April 30, 2014, between Tri-State and Kenneth V. Reif
10.17**†	Retention Agreement for Barbara A. Walz, effective as of April 30, 2014, between Tri-State and Barbara A. Walz
10.18**†	Executive Benefit Restoration Plan, dated December 12, 2014
10.19**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014
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
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

* 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 18, 2015.

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By: /s/ MICHEAL S. MCINNES

Name: Micheal S. McInnes
Title: *Chief Executive Officer*

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.

Signature	Title	Date
/s/ MICHEAL S. MCINNES Micheal S. McInnes	Chief Executive Officer (principal executive officer)	June 18, 2015
/s/ PATRICK L. BRIDGES Patrick L. Bridges	Senior Vice President and Chief Financial Officer (principal financial officer)	June 18, 2015
/s/ STEVEN J. LINDBECK Steven J. Lindbeck	Senior Manager Controller (principal accounting officer)	June 18, 2015
* Rick Gordon	Chairman, President and Director	June 18, 2015
* Tony Casados	Director	June 18, 2015
* Leo Brekel	Director	June 18, 2015
* Stuart Morgan	Director	June 18, 2015

Signature	Title	Date
* Matt M. Brown	Director	June 18, 2015
* Julie Kilty	Director	June 18, 2015
* Joseph Herrera	Director	June 18, 2015
* William Mollenkopf	Director	June 18, 2015
* Joseph Wheeling	Director	June 18, 2015
* Robert Bledsoe	Director	June 18, 2015
* Jerry Burnett	Director	June 18, 2015
* Richard Clifton	Director	June 18, 2015
* Wayne Connell	Director	June 18, 2015
* Lucas Cordova, Jr.	Director	June 18, 2015
* Jack Finnerty	Director	June 18, 2015

Signature	Title	Date
* Gary Fuchser	Director	June 18, 2015
* Jack Hammond	Director	June 18, 2015
* Ronald Hilkey	Director	June 18, 2015
* Ralph Hilyard	Director	June 18, 2015
* Donald Keairns	Director	June 18, 2015
* Hal Keeler	Director	June 18, 2015
* Gary Merrifield	Director	June 18, 2015
* Thaine Michie	Director	June 18, 2015
* Virginia Mondragon	Director	June 18, 2015
* Chris Morgan	Director	June 18, 2015
* Richard Newman	Director	June 18, 2015

Signature	Title	Date
* William Patterson	Director	June 18, 2015
Stanley Propp	Director	
* Timothy Rabon	Director	June 18, 2015
* Gary Rinker	Director	June 18, 2015
* Arthur Rodarte	Director	June 18, 2015
* Claudio Romero	Director	June 18, 2015
* Don Russell	Director	June 18, 2015
* Brian Schlagel	Director	June 18, 2015
* Gerald Seward	Director	June 18, 2015
* Jack Sibold	Director	June 18, 2015
* Charles J. Soehner	Director	June 18, 2015

Signature	Title	Date
* Darryl Sullivan	Director	June 18, 2015
* Jerry Thompson	Director	June 18, 2015
* Carl Trick II	Director	June 18, 2015
Douglas S. Turner	Director	
* Scott Wolfe	Director	June 18, 2015
* William Wright	Director	June 18, 2015
* Phillip Zochol	Director	June 18, 2015

*By: /s/ PATRICK L. BRIDGES

Patrick L. Bridges
Attorney-in-fact

Exhibit Index

Exhibit Number	Description
3.1†	Amended and Restated Articles of Incorporation of Tri-State Generation and Transmission Association, Inc.
3.2†	Amended and Restated Bylaws of Tri-State Generation and Transmission Association, Inc.
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
4.2†	Exchange and Registration Rights Agreement, dated October 30, 2014, between Tri-State Generation and Transmission Association, Inc. and Goldman, Sachs & Co.
4.3†	Form of Exchange Bond for 3.70% First Mortgage Bonds, Series 2014E-1, due 2024
4.4†	Form of Exchange Bond for 4.70% First Mortgage Bonds, Series 2014E-2, due 2044
4.5.1*	Loan Agreement, dated January 10, 1989, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.5.2*	Secured Promissory Note, dated January 10, 1989, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9028, in the original principal amount of $1,969,377
4.6.1*	Loan Agreement, dated April 10, 1992, between Tri-State and National Rural Utilities Cooperative Finance Corporation
4.6.2*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9034, in the original principal amount of $10,426,435.24
4.6.3*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9035, in the original principal amount of $38,220,475.57
4.6.4*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9038, in the original principal amount of $943,092.72
4.6.5*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9039, in the original principal amount of $821,815.11
4.6.6*	Secured Promissory Note, dated April 10, 1992, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9040, in the original principal amount of $32,224,821
4.7.1*	Master Loan Agreement, dated March 14, 1997, between Tri-State and National Rural Utilities Cooperative Finance Corporation

Exhibit Number	Description
4.7.2*	First Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated March 14, 1997
4.7.3*	Secured Promissory Note, dated March 14, 1997, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9044, in the original amount of $15,600,000
4.7.4*	Second Supplement to Master Loan Agreement, between Tri-State and National Rural Utilities Cooperative Finance Corporation, dated January 26 1999
4.7.5*	Secured Promissory Note, dated January 26, 1999, from Tri-State to National Rural Utilities Cooperative Finance Corporation, related to loan C-0047-9046, in the original amount of $1,172,665.68
4.8.1*	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
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.

Exhibit Number	Description
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*	Tri-State First Mortgage Bond, dated June 8, 2010, related to Series 2010A due in 2040, in the principal amount of $400,000,000
4.19.2*	Tri-State First Mortgage Bond, dated October 8, 2010, related to Series 2010A due in 2040, in the principal amount of $100,000,000
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
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
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
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

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
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
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
10.7†	Series 2009C Note Purchase Agreement, dated as of April 8, 2009, between Tri-State and various purchasers of the notes identified therein
10.8†	2014 Note Purchase Agreement, dated as of October 31, 2014, between Tri-State and various purchasers of the notes identified therein
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
10.10**†	Director Elective Deferred Fees Plan, effective January 1, 2005, executed December 11, 2008
10.11**†	Retention Agreement for Joel K. Bladow, effective as of April 30, 2014, between Tri-State and Joel K. Bladow
10.12**†	Retention Agreement for Patrick L. Bridges, effective as of April 30, 2014, between Tri-State and Patrick L. Bridges
10.13**†	Retention Agreement for Jennifer Godin Goss, effective as of April 30, 2014, between Tri-State and Jennifer Godin Goss
10.14**†	Retention Agreement for Bradford C. Nebergall, effective as of April 30, 2014, between Tri-State and Bradford C. Nebergall
10.15**†	Retention Agreement for John O' Flannigan, effective as of April 30, 2014, between Tri-State and John O' Flannigan
10.16**†	Retention Agreement for Kenneth V. Reif, effective as of April 30, 2014, between Tri-State and Kenneth V. Reif
10.17**†	Retention Agreement for Barbara A. Walz, effective as of April 30, 2014, between Tri-State and Barbara A. Walz
10.18**†	Executive Benefit Restoration Plan, dated December 12, 2014
10.19**†	Amended and Restated Pension Restoration Plan of Tri-State Generation and Transmission Association, Inc., dated December 12, 2014
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

Exhibit Number	Description
23.2†	Consent of Dorsey & Whitney LLP (included in Exhibit 5.1)
24.1†	Power of Attorney
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

* 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.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the reference to our firm under the caption “Experts” and to the use of our report dated March 3, 2015, in Amendment No. 1 to the Registration Statement (Form S-4 No. 333-203560) and related Prospectus of Tri-State Generation and Transmission Association, Inc. for the registration of $250,000,000 aggregate principal amount of 3.70% First Mortgage Bonds, Series 2014E-1, due 2024, and $250,000,000 aggregate principal amount of 4.70% First Mortgage Bonds, Series 2014E-2, due 2044.

/s/ Ernst & Young LLP
Denver, Colorado
June 18, 2015