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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

OR

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

For the transition period from to

Commission File No. 333-212006

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one): **Large Accelerated Filer** ☐ **Accelerated Filer** ☐ **Non-Accelerated Filer** ☒ (Do not check if a smaller reporting company) **Smaller Reporting Company** ☐

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

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

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2016

FORWARD-LOOKING STATEMENTS

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

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

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	June 30, 2016 (unaudited)	December 31, 2015
ASSETS		
Property, plant and equipment		
Electric plant		
In service	$ 5,617,294	$ 5,486,518
Construction work in progress	177,482	216,279
Total electric plant	5,794,776	5,702,797
Less allowances for depreciation and amortization	(2,305,465)	(2,240,732)
Net electric plant	3,489,311	3,462,065
Other plant	231,362	227,957
Less allowances for depreciation, amortization and depletion	(80,649)	(73,471)
Net other plant	150,713	154,486
Total property, plant and equipment	3,640,024	3,616,551
Other assets and investments		
Investments in other associations	124,571	123,686
Investments in and advances to coal mines	17,212	16,221
Restricted cash and investments	1,000	1,000
Intangible assets	21,972	25,634
Other noncurrent assets	12,419	12,139
Total other assets and investments	177,174	178,680
Current assets		
Cash and cash equivalents	158,813	144,587
Restricted cash and investments	4,712	9,530
Deposits and advances	32,166	21,673
Accounts receivable—Members	109,836	106,216
Other accounts receivable	15,076	14,270
Coal inventory	62,243	59,277
Materials and supplies	86,725	85,501
Total current assets	469,571	441,054
Deferred charges		
Regulatory assets	416,447	415,081
Prepayment—NRECA Retirement Security Plan	46,386	49,146
Other	132,071	122,535
Total deferred charges	594,904	586,762
Total assets	**$ 4,881,673**	**$ 4,823,047**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 959,686	$ 952,082
Accumulated other comprehensive income	543	589
Noncontrolling interest	108,879	108,757
Total equity	1,069,108	1,061,428
Long-term debt	3,153,082	3,273,538
Total capitalization	4,222,190	4,334,966
Current liabilities		
Member advances	11,336	9,403
Accounts payable	99,528	96,098
Short-term borrowings	94,948	—
Accrued expenses	31,218	30,045
Accrued interest	34,021	34,332
Accrued property taxes	17,964	27,395
Current maturities of long-term debt	110,113	91,419
Total current liabilities	399,128	288,692
Deferred credits and other liabilities		
Regulatory liabilities	92,685	45,000
Deferred income tax liability	28,067	28,629
Intangible liabilities	5,028	6,221
Asset retirement obligations	60,479	55,215
Other	66,944	57,423
Total deferred credits and other liabilities	253,203	192,488
Accumulated postretirement benefit and postemployment obligations	7,152	6,901
Total equity and liabilities	**$ 4,881,673**	**$ 4,823,047**

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	**2015**	**2016**	**2015**
Operating revenues				
Member electric sales	$ 275,517	$ 257,292	$ 547,286	$ 524,831
Non-member electric sales	26,666	29,785	56,788	64,848
Other	20,051	18,836	41,622	44,625
	322,234	305,913	645,696	634,304
Operating expenses				
Purchased power	78,170	71,284	149,205	144,421
Fuel	51,560	35,569	112,550	96,844
Production	57,016	70,377	107,998	123,897
Transmission	39,132	37,972	75,592	75,071
General and administrative	6,392	5,472	11,502	11,623
Depreciation, amortization and depletion	41,873	35,968	80,776	70,946
Coal mining	7,398	7,116	15,671	15,943
Other	3,690	3,605	9,020	7,625
	285,231	267,363	562,314	546,370
Operating margins	**37,003**	**38,550**	**83,382**	**87,934**
Other income				
Interest income	1,059	1,087	2,133	2,170
Capital credits from cooperatives	184	947	4,695	5,241
Other income	694	503	1,735	1,851
	1,937	2,537	8,563	9,262
Interest expense, net of amounts capitalized	35,924	34,910	71,344	71,073
Income taxes	350	—	350	—
Net margins including noncontrolling interest	2,666	6,177	20,251	26,123
Net (income) loss attributable to noncontrolling interest	(129)	107	(181)	287
Net margins attributable to the Association	**$ 2,537**	**$ 6,284**	**$ 20,070**	**$ 26,410**

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net margins including noncontrolling interest	$ 2,666	$ 6,177	$ 20,251	$ 26,123
Other comprehensive income (loss):				
Unrealized gain (loss) on securities available for sale	21	(7)	(1)	(23)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(23)	8	(45)	17
Income tax expense related to components of other comprehensive income (loss)	—	—	—	—
Other comprehensive income (loss)	(2)	1	(46)	(6)
Comprehensive income including noncontrolling interest	2,664	6,178	20,205	26,117
Net comprehensive (income) loss attributable to noncontrolling interest	(129)	107	(181)	287
Comprehensive income attributable to the Association	**$ 2,535**	**$ 6,285**	**$ 20,024**	**$ 26,404**

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)

	Six Months Ended June 30,	
	2016	2015
Patronage capital equity at beginning of period	$ 952,082	$ 908,669
Net margins attributable to the Association	20,070	26,410
Retirement of patronage capital	(12,466)	—
Patronage capital equity at end of period	**959,686**	**935,079**
Accumulated other comprehensive income (loss) at beginning of period	589	(828)
Unrealized loss on securities available for sale	(1)	(23)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(45)	17
Accumulated other comprehensive income (loss) at end of period	**543**	**(834)**
Noncontrolling interest at beginning of period	108,757	109,302
Net income (loss) attributable to noncontrolling interest	181	(287)
Equity distribution to noncontrolling interest	(59)	—
Noncontrolling interest at end of period	**108,879**	**109,015**
Total equity at end of period	**$ 1,069,108**	**$ 1,043,260**

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)

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Operating activities		
Net margins including noncontrolling interest	$ 20,251	$ 26,123
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	80,776	70,946
Amortization of intangible asset	3,662	3,662
Amortization of NRECA Retirement Security Plan prepayment	2,686	2,760
Amortization of debt issuance costs	940	929
Deferred membership withdrawal income	47,572	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(2,190)	(3,528)
Change in restricted cash and investments	(78)	29,192
Changes in operating assets and liabilities:		
Accounts receivable	(3,424)	8,977
Coal inventory	(2,965)	(21,927)
Materials and supplies	(1,224)	(2,838)
Accounts payable and accrued expenses	3,475	(2,097)
Accrued interest	(312)	1,662
Accrued property taxes	(9,431)	(8,580)
Other deferred credits - BNSF settlement	—	(29,381)
Other	(7,498)	1,374
Net cash provided by operating activities	**132,240**	**77,274**
Investing activities		
Purchases of plant	(93,953)	(150,447)
Changes in deferred charges	(7,698)	2,474
Proceeds from other investments	313	399
Net cash used in investing activities	**(101,338)**	**(147,574)**
Financing activities		
Changes in Member advances	754	(1,982)
Payments of long-term debt	(408,584)	(92,073)
Proceeds from issuance of debt	307,135	175,359
Increase in short-term borrowings, net	94,948	—
Retirement of patronage capital	(15,345)	(4,213)
Proceeds from investment in securities pledged as collateral	4,647	4,222
Other	(231)	323
Net cash provided by (used in) financing activities	**(16,676)**	**81,636**
Net increase in cash and cash equivalents	**14,226**	**11,336**
Cash and cash equivalents – beginning	**144,587**	**92,468**
Cash and cash equivalents – ending	**$ 158,813**	**$ 103,804**
Supplemental cash flow information:		
Cash paid for interest	$ 78,696	$ 76,548
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (4,525)	$ (2,277)

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

Tri-State Generation and Transmission Association, Inc.
Notes to Unaudited Consolidated Financial Statements
For the Three and Six Months Ended June 30, 2016 and 2015

NOTE 1 – PRESENTATION OF FINANCIAL INFORMATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. These unaudited consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015 filed with the SEC. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation, have been included. The results of operations for the three and six months ended June 30, 2016 and 2015 are not necessarily indicative of the results that may be expected for an entire year or any other period.

On June 30, 2016, Kit Carson Electric Cooperative, Inc. ("KCEC") withdrew from membership in us pursuant to the Membership Withdrawal Agreement ("Withdrawal Agreement"). The Withdrawal Agreement provided for the termination of the wholesale electric service contract between us and KCEC that extended through 2040 and the withdrawal of KCEC from membership in us. As part of the Withdrawal Agreement, we received $37 million net cash, which consists of $49.5 million as an early termination fee for withdrawing from membership in us offset by $12.5 million for the retirement of KCEC's patronage capital. This resulted in $47.6 million in other income, which was deferred by our Board of Directors ("Board") and is recorded in deferred credits and other liabilities on the statement of financial position. For each of the three most recent fiscal years and the six months ended June 30, 2016, KCEC constituted an average of approximately 2 percent of our revenue from our member distribution system ("Member") sales.

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 11 – Variable Interest Entities. Our consolidated financial statements also include our undivided interests in jointly owned facilities. All significant intercompany balances and transactions have been eliminated in consolidation.

Jointly Owned Facilities

We own undivided interests in three jointly owned generation facilities that are operated by the operating agent of each facility under joint facility ownership agreements with other utilities as tenants in common. These projects include the Yampa Project (operated by us), the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")) and the San Juan Project (operated by Public Service Company of New Mexico). Each participant in these agreements receives a portion of the total output of the generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of June 30, 2016 (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Station Units 1 and 2	24.00 %	$ 345,071	$ 230,002	$ 30,202
MBPP - Laramie River Station	24.13 %	394,964	291,120	14,306
San Juan Project – San Juan Unit 3	8.20 %	82,692	66,665	—
Total		$ 822,727	$ 587,787	$ 44,508

NOTE 2 – ACCOUNTING FOR RATE REGULATION

We are subject to the accounting requirements related to regulated operations. In accordance with these accounting requirements, some revenues and expenses have been deferred at the discretion of our Board, 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 in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses concurrent with their recovery in rates.

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

	June 30, 2016	December 31, 2015
Regulatory assets		
Deferred income tax expense (1)	$ 28,067	$ 28,629
Deferred prepaid lease expense- Craig 3 Lease (2)	12,947	16,183
Deferred prepaid lease expense- Springerville 3 Lease (3)	91,732	92,878
Goodwill – J.M. Shafer (4)	59,117	60,541
Goodwill – Colowyo Coal (5)	40,810	41,327
Deferred debt prepayment transaction costs (6)	171,130	175,444
Interest rate swaps (7)	12,644	—
Other	—	79
Total regulatory assets	416,447	415,081
Regulatory liabilities		
Deferred revenues (8)	45,000	45,000
Membership withdrawal (9)	47,572	—
Other	113	—
Total regulatory liabilities	92,685	45,000
Net regulatory asset	$ 323,762	$ 370,081

(1) A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be received or settled through future rate revenues.
(2) Deferral of loss on acquisition related to the Craig Generating Station Unit 3 prepaid lease expense upon acquisitions of equity interests in 2002 and 2006. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation and amortization expense in the amount of $6.5 million annually through the remaining original life of the lease ending in 2018 and recovered from our Members in rates.
(3) Deferral of loss on acquisition related to the Springerville Generating Station Unit 3 ("Springerville Unit 3") prepaid lease expense upon acquiring a controlling interest in the Springerville Unit 3 Partnership LP ("Springerville Partnership") in 2009. The regulatory asset for the deferred prepaid lease expense is being amortized to depreciation and amortization expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Members in rates.

(4) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP ("TCP") in December 2011. Goodwill is being amortized to depreciation and amortization expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Members in rates.
(5) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is being amortized to depreciation and amortization expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Members in rates.
(6) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation and amortization expense in the amount of $8.6 million annually over the 21.4-year average life of the new debt issued and recovered from our Members in rates.
(7) Represents deferral of the unrealized loss related to the change in fair value of forward starting interest rate swaps that were entered into in order to hedge interest rates on anticipated future borrowings. Upon settlement of these interest rate swaps, the realized gain or loss will be amortized to interest expense over the term of the associated long-term debt borrowing. See Note 6 – Long-Term Debt and Note 10 – Fair Value.
(8) 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.
(9) Represents the deferral of the recognition of other income of $47.6 million recorded in connection with the June 30, 2016 withdrawal of KCEC from membership in us pursuant to the Withdrawal Agreement. See Note 1 – Presentation of Financial Information.

NOTE 3 – INVESTMENTS IN OTHER ASSOCIATIONS

Investments in other associations includes investments in the patronage capital of other cooperatives (accounted for using the cost method) and other required investments in the organizations. Under this method, our investment in a cooperative increases when a cooperative allocates patronage capital credits to us and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

NOTE 4 – RESTRICTED CASH AND INVESTMENTS

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

We have investments in U.S. Treasury Notes pledged as collateral in connection with the in-substance defeasance for the principal outstanding and future interest payments on the Coal Contract Receivable Collateralized Bonds ("Colowyo Bonds"). The balances in these investments are described as investments in securities pledged as collateral in the table below. As of June 30, 2016, the entire $3.8 million balance of the defeasance investment is for Colowyo Bond debt payments due within one year and is, therefore, a current asset on the consolidated statements of financial position. The Colowyo Bonds mature in November 2016.

Restricted cash and investments are as follows (dollars in thousands):

	June 30, 2016	December 31, 2015
Investments in securities pledged as collateral	$ 3,774	$ 8,671
Funds restricted by contract	938	859
Restricted cash and investments - current	4,712	9,530
Funds restricted by contract	1,000	1,000
Restricted cash and investments - noncurrent	1,000	1,000
Total restricted cash and investments	$ 5,712	$ 10,530

NOTE 5 – OTHER DEFERRED CHARGES

We make expenditures for preliminary surveys and investigations for the purpose of determining the feasibility of contemplated generation and transmission projects. If construction results, the preliminary survey and investigation expenditures will be reclassified to electric plant - construction work in progress. If the work is abandoned, the related preliminary survey and investigation expenditures will be charged to the appropriate operating expense account or the expense could be deferred as a regulatory asset to be recovered from our Members in rates subject to approval by our Board, which has budgetary and rate-setting authority. As of June 30, 2016, preliminary surveys and investigations was primarily comprised of expenditures for the Holcomb Station Project of $89.1 million.

We make advance payments to the operating agents of jointly owned facilities to fund our share of costs expected to be incurred under each project including MBPP – Laramie River Station, Yampa Project – Craig Station Units 1 and 2, San Juan Project – San Juan Unit 3. We also make advance payments to the operating agent of Springerville Unit 3.

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

	June 30, 2016	December 31, 2015
Preliminary surveys and investigations	$ 108,824	$ 107,146
Advances to operating agents of jointly owned facilities	19,377	11,537
Other	3,870	3,852
Total other deferred charges	$ 132,071	$ 122,535

NOTE 6 – LONG-TERM DEBT

The mortgage notes payable and pollution control revenue bonds are secured on a parity basis by a Master First Mortgage Indenture, Deed of Trust and Security Agreement except for two unsecured notes in the aggregate amount of $52.6 million as of June 30, 2016. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. The Colowyo Bonds are secured by funds deposited with the trustee as part of the in-substance defeasance and an unconditional guarantee by us. All long-term debt contains certain restrictive financial covenants, including a debt service ratio requirement and equity to capitalization ratio requirement.

We have a secured revolving credit facility with Bank of America, N.A. and CoBank, ACB as Joint Lead Arrangers in the amount of $750 million ("Revolving Credit Agreement") that expires on July 26, 2019. We had no outstanding borrowings at June 30, 2016 and $271 million at December 31, 2015. There is a 364-day, direct pay letter of credit issued under the Revolving Credit Agreement and provided by Bank of America, N.A. for the $46.8 million Moffat County, CO, Variable Rate Demand Pollution Control Revenue Refunding Bonds, Series 2009.

On May 23, 2016, we issued our First Mortgage Bonds, Series 2016A ("Series 2016A Bonds") in an unregistered offering pursuant to Rule 144A under the Securities Act of 1933 with an aggregate principal amount of $250 million. The Series 2016A Bonds mature on June 1, 2046 and bear interest at a rate of 4.25 percent per annum. We utilized the proceeds from the Series 2016A Bonds primarily to repay outstanding indebtedness under the Revolving Credit Agreement. In connection with the Series 2016A Bonds, we entered into an exchange and registration rights agreement pursuant to which we agreed to file a registration statement relating to an exchange offer for our Series 2016A Bonds. On June 27, 2016, we commenced an offer to exchange all of the unregistered $250 million aggregate principal amount of the Series 2016A Bonds for $250 million aggregate principal amount of registered Series 2016A Bonds. We completed the exchange offer in July 2016 which satisfied our obligations under the exchange and registration rights agreement. The exchange offer did not represent a new financing transaction and there were no proceeds to us when the exchange offer was completed.

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

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

	June 30, 2016	December 31, 2015
Total debt	$ 3,275,094	$ 3,371,679
Less debt issuance costs	(23,110)	(21,201)
Less debt discounts	(10,669)	(8,739)
Plus debt premiums	21,880	23,218
Total debt adjusted for discounts, premiums and debt issuance costs	3,263,195	3,364,957
Less current maturities	(110,113)	(91,419)
Long-term debt	$ 3,153,082	$ 3,273,538

We are exposed to certain risks in the normal course of operations in providing a reliable and affordable source of wholesale electricity to our Members. These risks include interest rate risk, which represents the risk of increased operating expenses and higher rates due to increases in interest rates related to anticipated future long-term borrowings. To manage this exposure, we have entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate exposure. We anticipate settling these swaps in conjunction with the issuance of future long-term debt. See Note 2 – Accounting for Rate Regulation and Note 10 – Fair Value.

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

	Notional Amount	Fixed Rate (1)	Benchmark Interest Rate (2)	Effective Date	Maturity Date
Interest rate swap - April 2016	$ 90,000	2.355 %	30 year - LIBOR	April 2019	April 2049
Interest rate swap - June 2016	80,000	2.304 %	30 year - LIBOR	June 2019	June 2049
	$ 170,000				

(1) We will pay.
(2) We will receive.

NOTE 7 – SHORT-TERM BORROWINGS

Commercial Paper

We established a commercial paper program in May 2016 under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper sublimit under our Revolving Credit Agreement, which is the lesser of $500 million or the amount available under our Revolving Credit Agreement. The commercial paper issuances are used to provide an additional financing source for our short-term liquidity needs. The maturities of the commercial paper issuances vary, but may not exceed 397 days from the date of issue. The commercial paper notes are classified as current and are included in current liabilities as short-term borrowings on the consolidated statements of financial position.

Commercial paper consisted of the following (dollars in thousands):

	June 30, 2016	December 31, 2015
Commercial paper outstanding net of discounts	$ 94,948	$ —
Weighted average interest rate	0.69 %	N/A

NOTE 8 – ASSET RETIREMENT OBLIGATIONS

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

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

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

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

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

	June 30, 2016	December 31, 2015
Asset retirement obligation at beginning of period	$ 55,215	$ 53,754
Liabilities incurred	5,453	1,802
Liabilities settled	(694)	(3,028)
Accretion expense	1,330	3,324
Change in cash flow estimate	(825)	(637)
Asset retirement obligation at end of period	$ 60,479	$ 55,215

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

NOTE 9 – INCOME TAXES

We are a taxable cooperative subject to federal and state taxation. As a taxable electric cooperative, we are allowed a tax exclusion for margins allocated as patronage capital. We utilize the liability method of accounting for income taxes. Accordingly, changes in deferred tax assets or liabilities result in the establishment of a regulatory asset or liability. A regulatory asset or liability associated with deferred income taxes generally represents the future increase or decrease in income taxes payable that will be settled or received through future rate revenues. Income tax expense was $350,000 for the three and six months ended June 30, 2016 and there was no income tax expense or benefit for the three and six months ended June 30, 2015.

NOTE 10 – 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 are based upon quoted prices for identical instruments traded in active (exchange-traded) markets. Valuations are obtained from readily available pricing sources for market transactions (observable market data) involving identical assets or liabilities.
>
> Level 2 inputs are based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active and model-based valuation techniques (such as option pricing models, discounted cash flow models) for which all significant assumptions are observable in the market.
>
> Level 3 inputs consist of unobservable market data which is typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity.

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

Marketable Securities

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

	As of June 30, 2016		As of December 31, 2015	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Marketable securities	$ 880	$ 1,008	$ 1,022	$ 1,151

Cash Equivalents

We invest portions of our cash and cash equivalents in commercial paper, money market funds, and other highly liquid investments. The fair value of these investments approximates our cost basis in the investments. In aggregate, the fair value was $49.1 million as of June 30, 2016 and $75.1 million as of December 31, 2015, respectively.

Debt

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

	As of June 30, 2016		As of December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Total debt	$ 3,275,094	$ 3,805,718	$ 3,371,679	$ 3,616,946

Interest Rate Swaps

We have entered into forward starting interest rate swaps to hedge a portion of our future long-term debt interest rate expense. These interest rate swaps are derivative instruments in accordance with ASC 815, *Derivatives and Hedging,* and are recorded at fair value on a recurring basis. The estimated fair value of these interest rate swaps utilizes observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs) and is included in other deferred credits and other liabilities on our consolidated statements of financial position. At June 30, 2016, the fair value of our interest rate swaps was $12.6 million.

NOTE 11 – VARIABLE INTEREST ENTITIES

The following is a description of our financial interests in variable interest entities that we consider significant. This includes an entity for which we are determined to be the primary beneficiary and therefore consolidate and also entities for which we are not the primary beneficiary and therefore do not consolidate.

Consolidated Variable Interest Entity

Springerville Partnership: We own a 51 percent equity interest, including the 1 percent general partner equity interest, in the Springerville Partnership, which is the 100 percent owner of Springerville Unit 3 Holding LLC ("Owner Lessor") of the Springerville Unit 3. We, as general partner, have the full, exclusive and complete right, power and discretion to operate, manage and control the affairs of the Springerville Partnership and take certain actions necessary to maintain the Springerville Partnership in good standing without the consent of the limited partners. Additionally, the Owner Lessor has historically not demonstrated an ability to finance its activities without additional financial support. The financial support is provided by our remittance of lease payments in order to permit the Owner Lessor, the holder of the Springerville Unit 3 assets, to pay the debt obligations and equity returns of the Springerville Partnership. We have the primary risk (expense) exposure in operating the Springerville Unit 3 assets and are responsible for 100 percent of the operation, maintenance and capital expenditures of Springerville Unit 3 and the decisions related to those expenditures including budgeting, financing and dispatch of power. Based on all these facts, it was determined that we are the primary beneficiary of the Owner Lessor. Therefore, the Springerville Partnership and Owner Lessor have been consolidated by us.

Our consolidated statements of financial position include the Springerville Partnership's net electric plant of $842.8 million and $853.3 million at June 30, 2016 and December 31, 2015, respectively, the long-term debt of $473.1 million and $511.0 million at June 30, 2016 and December 31, 2015, respectively, accrued interest associated with the long-term debt of $13.4 million and $14.3 million at June 30, 2016 and December 31, 2015, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $108.9 million and $108.8 million at June 30, 2016 and December 31, 2015, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $5.3 million for the three months ended June 30, 2016 and the comparable period in 2015. Our consolidated statements of operations also include interest expense of $7.6 million for the three months ended June 30, 2016 and $8.0 million for the comparable period in 2015. Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization of $10.5 million for the six months ended June 30, 2016 and the comparable period in 2015. Our consolidated statements of operations also include interest expense of $15.3 million for the six months ended June 30, 2016 and $16.2 million for the comparable period in 2015. The net income and 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, Inc. ("WFA"): WFA is a non-profit membership corporation organized for the purpose of acquiring and supplying fuel resources to its members, which includes us. WFA supplies fuel to MBPP for the use of the Laramie River Station through its ownership in Western Fuels-Wyoming. We also receive coal supplies directly from WFA for the Escalante Generating Station in New Mexico and spot coal for the Springerville Unit 3 in Arizona. The pricing structure of the coal supply agreements with WFA is designed to recover the mine operating costs of the mine supplying the coal and therefore the coal sales agreements provide the financial support for the mine operations. There isn't sufficient equity at risk for WFA to finance its activities without additional financial support. Therefore, WFA is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFA's economic performance (acquiring and supplying fuel resources) is held by the members who are represented on the WFA board of directors whose actions require joint approval. Therefore, since there is shared power over the significant activities of WFA, we are not the primary beneficiary of WFA and the entity is not consolidated. Our investment in WFA, accounted for using the cost method, was $2.7 million at June 30, 2016 and $2.3 million at December 31, 2015, respectively, and is included in investments in other associations.

Western Fuels – Wyoming ("WFW"): WFW, the owner and operator of the Dry Fork Mine in Gillette, WY, was organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 24.13 percent undivided interest) own the remaining 25 percent of class BB shares of WFW. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Dry Fork Mine and therefore the coal supply agreements provide the financial support for the operation of the Dry Fork Mine. There isn't sufficient equity at risk at WFW for it to finance its activities without additional financial support. Therefore, WFW is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact WFW's economic performance (which includes operations, maintenance and reclamation activities) is shared with the equity interest holders since each member has representation on the WFW board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of WFW and the entity is not consolidated.

Trapper Mining, Inc. ("Trapper Mining"): Trapper Mining is a cooperative organized for the purpose of mining, selling and delivering coal from the Trapper Mine to the Craig Generating Station Units 1 and 2 through long-term coal supply agreements. Trapper Mining is jointly owned by some of the participants of the Yampa Project. We have a 26.57 percent cooperative member interest in Trapper Mining. The pricing structure of the coal supply agreements is designed to recover the costs of production of the Trapper Mine and therefore the coal supply agreements provide the financial support for the operation of the Trapper Mine. There isn't sufficient equity at risk for Trapper Mining to finance its activities without the additional financial support. Therefore, Trapper Mining is considered a variable interest entity in which we have a variable interest. The power to direct the activities that most significantly impact Trapper Mining's economic performance (which includes operations, maintenance and reclamation activities) is shared with the cooperative members since each member has representation on the Trapper Mining board of directors whose actions require joint approval. Therefore, we are not the primary beneficiary of Trapper Mining and the entity is not consolidated. We record our investment in Trapper Mining using the equity method. Our membership interest in Trapper Mining was $14.3 million at June 30, 2016 and $14.1 million at December 31, 2015.

NOTE 12 – LEGAL

On February 17, 2016, we filed a Petition for Declaratory Order with the United States Federal Energy Regulatory Commission ("FERC") seeking a declaratory order from FERC finding that the fixed cost recovery mechanism in our proposed revised Board policy is consistent with the provisions of Public Utility Regulatory Policies Act of 1978, as amended and the implementing regulations of FERC. The revised Board policy provides for recovery of the unrecovered fixed costs directly from that Member as a result of that Member purchasing power from a "qualifying facility" in an amount that causes it to exceed the 5 percent limitation on that Member's self-supply of power pursuant to its wholesale electric service contract, rather than allocating the costs among all of our Members. The fixed cost recovery is calculated based on the difference between our wholesale rate to our Members and our avoided costs. On June 16, 2016, FERC denied our Petition for Declaratory Order related to the fixed cost recovery mechanism in our revised Board policy. On July 18, 2016, we filed a Request for Rehearing with FERC regarding FERC's June 16 order. In addition, five other generation and transmission cooperatives have filed a Request for Rehearing with FERC. We are evaluating the impact of FERC's denial and cannot predict the outcome of our July 18 request for rehearing filed with FERC.

NOTE 13 – NEW ACCOUNTING PRONOUNCEMENTS

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-13, *Financial Instruments – Credit Losses (Topic 362).* The amendment requires that financial assets measured at amortized cost be presented net of expected credit losses. The expected credit loss reflects management's current estimate of credit losses that are expected to occur over the remaining life of a financial asset. This is in contrast to existing guidance whereby credit losses generally are not recognized until they are incurred. This amendment is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted. The guidance is applied using a modified retrospective transition method. We are currently evaluating the impact that the standard will have on our financial position and results of operations.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842).* This amendment requires a lessee to recognize substantially all leases (whether operating or finance leases) on the balance sheet as a right-of-use asset and an associated lease liability. Short-term leases of 12 months or less are excluded from this amendment. A right-of-use asset represents a lessee's right to use (control the use of) the underlying asset for the lease term. A lease liability represents a lessee's liability to make lease payments. The right-of-use asset and the lease liability are initially measured at the present value of the lease payments over the lease term. For finance leases, the lessee subsequently recognizes interest expense and amortization of the right-of-use asset, similar to accounting for capital leases under current GAAP. For operating leases, the lessee subsequently recognizes straight-line lease expense over the life of the lease. Lessor accounting remains substantially the same as that applied under current GAAP. This amendment is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The guidance is to be applied using a modified retrospective transition method with the option to elect a package of practical expedients. We are currently evaluating the impact of this amendment on our financial position and results of operations.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. The amendments in this ASU require that equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) be measured at fair value, with subsequent changes in fair value recognized in net income. An entity may choose to measure equity investments that do not have readily determinable fair value at cost minus impairment. The pronouncement impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. Also, an entity should present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application by public business entities to financial statements of fiscal years or interim periods that have not yet been issued or, by all other entities, that have not yet been made available for issuance are permitted as of the beginning of the fiscal year of adoption. An entity should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments related to equity securities without readily determinable fair values (including disclosure requirements) should be applied prospectively to equity investments that exist as of the date of adoption of the update. We are currently evaluating the impact of this amendment on our financial position and results of operations.

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

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, as amended by subsequent ASU amendments issued in 2015 and 2016. In July 2015, FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU 2014-09 replaces current revenue guidance, which was based on a risks and rewards model, with a transfer of control model. The core principle under the new transfer of control model states that revenue should be recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. To achieve the core principle, this amendment requires the following steps: (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This amendment also requires additional quantitative and qualitative disclosures sufficient enough to enable users of financial information to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For public business entities, this amendment is effective for the fiscal year beginning January 1, 2018 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes footnote disclosures). Reporting entities have the option to adopt the standard as early as the original January 1, 2017 effective date of this amendment. We are currently evaluating the impact of this amendment on our financial position and results of operations.

Item 2. 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 member distribution systems, or Members, that serve major parts of Colorado, Nebraska, New Mexico and Wyoming. We currently have 43 Members after the withdrawal in June 2016 of Kit Carson Electric Cooperative, Inc., or KCEC, from membership in us. 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. As of June 30, 2016, our 43 Members served approximately 600,000 retail electric meters over a nearly 200,000 square-mile area. We sold 8.8 million megawatt hours, or MWhs, for the six months ended June 30, 2016, of which 86.7 percent was to Members. Total revenue from electric sales was $604.1 million for the six months ended June 30, 2016, of which 90.6 percent was from Member sales.

We have entered into substantially similar wholesale electric service contracts with each Member extending through 2050 for 42 Members (which constitute approximately 94.5 percent of our revenue from Member sales for the six months ended June 30, 2016) and extending through 2040 for the remaining Member (Delta Montrose Electric Association, which constitutes approximately 3.6 percent of our revenue from Member sales for the six months ended June 30, 2016), 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 June 30, 2016, after the withdrawal of KCEC from membership in us, 16 Members have enrolled in this program with capacity totaling approximately 95 megawatts.

On June 30, 2016, KCEC withdrew from membership in us pursuant to the Membership Withdrawal Agreement, or Withdrawal Agreement. The Withdrawal Agreement provided for the termination of the wholesale electric service contract between us and KCEC that extended through 2040 and the withdrawal of KCEC from membership in us. As part of the Withdrawal Agreement, we received $37 million net cash, which consists of $49.5 million as an early termination fee for withdrawing from membership in us offset by $12.5 million for the retirement of KCEC's patronage capital. This resulted in $47.6 million in other income, which was deferred by our Board of Directors, or Board, and is recorded in deferred credits and other liabilities on the statement of financial position. For each of the three most recent fiscal years and the six months ended June 30, 2016, KCEC constituted an average of approximately 2 percent of our revenue from Member sales.

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

Summary of Critical Accounting Policies

As of June 30, 2016, there have been no material changes in our critical accounting policies as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

Factors Affecting Results

Margins and Patronage Capital

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

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. Pursuant to the policy, we target rates payable by our Members to produce financial results in excess of the requirements under our indenture, dated effective as of December 15, 1999, or Master Indenture, between us and Wells Fargo Bank, National Association, as trustee. On a periodic basis, our Board 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 determines that our financial condition will not be impaired, a portion of retained patronage capital may be retired. Historically, patronage capital has been retired in order of priority according to the year in which the patronage capital was furnished and credited; however, our bylaws provide the Board with discretion on order of retirement. As of June 30, 2016, patronage capital equity was $959.7 million. To date, we have retired approximately $325.5 million of patronage capital to our Members, including the $12.5 million we retired as part of KCEC's withdrawal from membership in us.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Rates for electric power sales to our Members consist of two billing components: an energy rate and a demand rate. Member rates for energy and demand are set by our Board, consistent with adequate electrical reliability and sound fiscal policy. Energy is the physical electricity delivered through our transmission system to our Members. Approved by our Board in September 2015 and effective January 1, 2016, our 2016 wholesale rate (A-39 rate) has an energy rate billed based upon a price per kilowatt hour, or kWh, of energy delivered and a demand rate billed on the Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Friday, with the exception of six holidays. In 2015, our wholesale rate (A-38 rate) had a different rate design that incorporated seasonal average demand rates. The monthly average demand was calculated by dividing each Member's total monthly energy (kWh) usage by the total hours in the month. The A-38 rate design also had an energy rate that incorporated an on-peak and off-peak period. We developed demand response and energy shaping products to compliment the A-38 rate schedule. The participating Member's monthly statements were adjusted using the demand response and energy shaping product incentives for Members utilizing those products. In November 2014, we implemented an optional rate (TR-1) available to our non-New Mexico Members, effective December 1, 2014 through December 31, 2015. The TR-1 optional rate had an energy rate billed based upon a price per kWh of energy delivered and a demand rate based upon our Member's highest thirty-minute integrated total demand measured using the Member's coincident peak during our peak period in each monthly billing period during our summer peak period or the winter peak period. Three Members elected this TR-1 optional rate.

Although rates established by our Board are generally not subject to regulation by federal, state or other governmental agencies, we are currently required to submit our rates to the New Mexico Public Regulation Commission, or NMPRC. As discussed below, we are involved in proceedings pending in New Mexico regarding efforts by the NMPRC related to our prior wholesale rates payable by our Members.

As required by New Mexico law, we file our rates to our New Mexico Members with the NMPRC, which has regulatory authority over rate increases in New Mexico, only in the event three or more of our New Mexico Members file a request for such a review and such review is found to be qualified by the NMPRC. In 2012, three of our New Mexico Members filed protests with the NMPRC of our A-37 wholesale rate that we filed with the NMPRC and which was scheduled to become effective on January 1, 2013. The NMPRC suspended the rate filing in New Mexico and appointed a hearing examiner to conduct a hearing and establish reasonable rate schedules pursuant to New Mexico law. In 2013, four of our New Mexico Members filed protests with the NMPRC of our A-38 wholesale rate that we filed with the NMPRC and was scheduled to become effective on January 1, 2014. The NMPRC suspended the A-38 rate filing and assigned the consolidated A-37 and A-38 rate filings to a hearing examiner. In 2014, we and the New Mexico Members executed a preliminary mediation agreement providing for a temporary rate rider through no later than December 31, 2015 and a suspension of the procedural schedule related to the rate protest to allow the parties time to proceed with more extensive discussions on a global settlement. We filed notice of the temporary rate rider with the NMPRC and it became effective on October 2, 2014. The temporary rate rider was applied in conjunction with the 2012 wholesale rate to recover additional revenue from the New Mexico Members in an annualized amount of $7 million per year, which was prorated beginning October 2 for 2014. In 2015, we gave notice, as required by New Mexico law, to the NMPRC of our A-39 wholesale rate. No New Mexico Member filed a protest with the NMPRC of the A-39 rate and thus the A-39 rate became effective on January 1, 2016 without NMPRC review or approval. In December 2015, we and the New Mexico Members filed a joint motion with the NMPRC seeking continuation of the suspension of the procedural schedule related to the rate protests to allow the parties additional time to proceed with further negotiations towards a global settlement. In January 2016, the NMPRC ordered that the procedural schedule related to the rate protests remains suspended until further order of the NMPRC.

Master Indenture

As of June 30, 2016, we had approximately $2.8 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 Debt Service Ratio (as defined in the Master Indenture), or 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 Equity to Capitalization Ratio (as defined in the Master Indenture) of 18 percent at the end of each fiscal year.

Tax Status

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

Results of Operations

General

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

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

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

Three months ended June 30, 2016 compared to three months ended June 30, 2015

Operating Revenues

Member electric sales increased 145,247 MWhs, or 4.0 percent, to 3,770,267 MWhs for the three months ended June 30, 2016 compared to 3,625,020 MWhs for the same period in 2015. The increase in MWhs sold in 2016 resulted in an increase of $18.2 million, or 7.1 percent, in Member electric sales revenue to $275.5 million for the three months ended June 30, 2016 compared to $257.3 million for the same period in 2015. The increase in revenue was primarily due to continued operation of large gas processing loads that came on line during the third and fourth quarter of 2015 and residential growth along the Front Range.

Non-member electric sales increased 64,699 MWhs, or 11.9 percent, to 610,787 MWhs for the three months ended June 30, 2016 compared to 546,088 MWhs for the same period in 2015. Non-member electric sales revenue decreased $3.1 million, or 10.4 percent, to $26.7 million for the three months ended June 30, 2016 compared to $29.8 million for the same period in 2015. The increase of 64,699 MWhs was comprised of an increase of 109,051 MWhs of short-term non-member sales and a decrease of 44,352 MWhs in long-term firm sales to non-members due to the expiration of several higher priced long-term power sales arrangements on December 31, 2015 and March 31, 2016 that were not renewed. The decrease in long-term firm sales resulted in a decrease in non-member revenue of $2.9 million. Although short-term non-member sales increased (which were made at spot market prices that are lower than the firm sales) revenue associated with such sales decreased by $206,000 due to a decrease in spot market rates in 2016 as compared to 2015.

Operating Expenses

Purchased power increased 244,383 MWhs, or 15.0 percent, to 1,870,722 MWhs for the three months ended June 30, 2016 compared to 1,626,339 MWhs for the same period in 2015. Purchased power expense increased $6.9 million, or 9.7 percent, to $78.2 million for the three months ended June 30, 2016 compared to $71.3 million for the same period in 2015. The increase in expense was primarily due to the increase in MWhs purchased partially offset by a 5.0 percent decrease in the average cost per MWh of purchased power resulting from lower market prices for power.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense increased $16.0 million, or 44.9 percent, to $51.6 million for the three months ended June 30, 2016 compared to $35.6 million for the same period in 2015. The increase in expense was primarily due to higher coal expense at our Craig Generating Station resulting from an increase in generation and lower coal expense in the second quarter of 2015 resulting from the one-time recognition of $24.4 million as a reduction to fuel expense because of the BNSF rate settlement. The effect of the BNSF rate settlement was partially offset by lower coal expense at our Nucla Generating Station due to a planned outage.

Production expense decreased $13.4 million, or 19.0 percent, to $57.0 million for the three months ended June 30, 2016 compared to $70.4 million for the same period in 2015. The decrease in expense was primarily due to a decrease in maintenance outages in 2016 (generation maintenance expense was higher in 2015 than in 2016 due to scheduled generation maintenance expenses incurred in 2015 at our Craig Generating Station and Laramie River Station).

Depreciation and amortization expense increased $5.9 million, or 16.4 percent, to $41.9 million for the three months ended June 30, 2016 compared to $36.0 million for the same period in 2015. The increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. In addition, depreciation expense increased (beginning in the third quarter 2015) at the San Juan Generating Station Unit 3 due to a shortened economic life associated with the anticipated December 31, 2017 retirement date of the unit.

Six months ended June 30, 2016 compared to six months ended June 30, 2015

Operating Revenues

Member electric sales increased 190,994 MWhs, or 2.6 percent, to 7,599,700 MWhs for the six months ended June 30, 2016 compared to 7,408,706 MWhs for the same period in 2015. The increase in MWhs sold in 2016 resulted in an increase of $22.5 million, or 4.3 percent, in Member electric sales revenue to $547.3 million for the six months ended June 30, 2016 compared to $524.8 million for the same period in 2015. The increase in revenue was primarily due to continued operation of large gas processing loads that came on line during the third and fourth quarter of 2015 and residential growth along the Front Range.

Non-member electric sales increased 28,460 MWhs, or 2.5 percent, to 1,165,872 MWhs for the six months ended June 30, 2016 compared to 1,137,412 MWhs for the same period in 2015. Non-member electric sales revenue decreased $8.1 million, or 12.4 percent, to $56.8 million for the six months ended June 30, 2016 compared to $64.9 million for the same period in 2015 despite the increase in MWhs. The increase of 28,460 MWhs was comprised of an increase of 167,135 MWhs of short-term non-member sales and a decrease of 138,675 MWhs in long-term firm sales to non-members due to the expiration of several higher priced long-term power sales arrangements on December 31, 2015 and March 31, 2016 that were not renewed. The decrease in long-term firm sales resulted in a decrease in non-member revenue of $7.7 million. Although short-term non-member sales increased (which were made at spot market prices that are lower than the firm sales) revenue associated with such sales decreased by $348,000 due to a decrease in spot market rates in 2016 as compared to 2015.

Other operating revenue consists primarily of wheeling, transmission, and lease revenues, coal sales and revenue from supplying steam and water to a paper manufacturer located adjacent to the Escalante Generating Station. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines. Transmission revenue is from our membership in the Southwest Power Pool, a regional transmission organization which began on January 1, 2016. The lease revenue is primarily from certain power sales arrangements that are required to be accounted for as operating leases since the arrangements are in substance leases because they convey to others the right to use power generating equipment for a stated period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine per a contract ending in 2017 to other joint owners in the Yampa Project. Other revenue decreased $3.0 million, or 6.7 percent, to $41.6 million for the six months ended June 30, 2016 compared to $44.6 million for the same period in 2015. The decrease in other operating revenue was primarily due to a $2.6 million decrease in coal sales to other joint owners in the Yampa Project, a $3.6 million decrease in lease revenue due to the expiration of power sales arrangements at our Knutson and Limon Generating Stations, and a $442,000 decrease in steam and water revenue. These decreases in other revenue were partially offset by a $3.5 million increase in transmission revenue resulting from our membership in the Southwest Power Pool.

Operating Expenses

Fuel expense increased $15.8 million, or 16.2 percent, to $112.6 million for the six months ended June 30, 2016 compared to $96.8 million for the same period in 2015. The increase in expense was primarily due to lower coal expense in the second quarter of 2015 resulting from the one-time recognition of $24.4 million as a reduction to fuel expense because of the BNSF rate settlement. The effect of the BNSF rate settlement was partially offset by fewer coal deliveries and planned maintenance outages.

Production expense decreased $15.9 million, or 12.8 percent, to $108.0 million for the six months ended June 30, 2016 compared to $123.9 million for the same period in 2015. The decrease in expense was primarily due to a decrease in maintenance outages in 2016 (generation maintenance expense was higher in 2015 than in 2016 due to scheduled generation maintenance expenses incurred in 2015 at our Craig Generating Station and Laramie River Station).

Depreciation and amortization expense increased $9.9 million, or 13.9 percent, to $80.8 million for the six months ended June 30, 2016 compared to $70.9 million for the same period in 2015. The increase in expense was primarily due to additions of equipment throughout our transmission system and at our generating stations. In addition, depreciation expense increased (beginning in the third quarter 2015) at the San Juan Generating Station Unit 3 due to a shortened economic life associated with the anticipated December 31, 2017 retirement date of the unit.

Financial condition as of June 30, 2016 compared to December 31, 2015

Assets

Construction work in progress decreased $38.8 million, or 17.9 percent, to $177.5 million as of June 30, 2016 compared to $216.3 million as of December 31, 2015. The decrease was primarily due to transfers to electric plant in service for completed projects of $118.8 million (the largest project was completion of the Burlington-Wray 230 KV transmission line of $56.5 million) offset by capital expenditures of $82.0 million related to various generation and transmission capital improvements and system upgrades.

Cash and cash equivalents increased $14.2 million, or 9.8 percent, to $158.8 million as of June 30, 2016 compared to $144.6 million as of December 31, 2015. The increase in cash and cash equivalents was primarily due to $248.0 million of proceeds from the issuance of the First Mortgage Bonds, Series 2016A, or Series 2016A Bonds, $62.0 million of proceeds from our secured revolving credit facility, or Revolving Credit Agreement, and $234.9 million of proceeds from the issuance of commercial paper. Additionally, cash increased as a result of receiving $37.0 million of net cash related to the withdrawal of KCEC from membership in us. Partially offsetting these increases in cash were debt payments of $408.6 million (principally $333.0 million on our Revolving Credit Agreement, $27.1 million on the First Mortgage Obligations, Series 2009C, $37.0 million on the Springerville certificates and $4.5 million on the Colowyo Bonds) and $140 million of commercial paper payments (maturities).

Restricted cash and investments consist of funds designated by our Board for specific uses and funds restricted by contract or other legal reasons and investments in securities pledged as collateral in connection with the in-substance defeasance of debt assumed in the 2011 acquisition of Colowyo Coal. Restricted cash and investments decreased $4.8 million, or 45.8 percent, to $5.7 million as of June 30, 2016 compared to $10.5 million as of December 31, 2015. The decrease was primarily due to $4.6 million of investment in securities pledged as collateral associated with debt that matured during the second quarter of 2016.

Deposits and advances increased $10.5 million, or 48.4 percent, to $32.2 million as of June 30, 2016 compared to $21.7 million as of December 31, 2015. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These payments are being amortized to expense over the term of the related insurance, membership or license period.

Other deferred charges increased $9.6 million, or 7.8 percent, to $132.1 million as of June 30, 2016 compared to $122.5 million as of December 31, 2015. The increase was primarily due to an increase of $7.8 million related to advance payments to the operating agents of jointly owned facilities and Springerville Unit 3 to fund our share of operational costs and capital projects expected to be incurred under each project. Also, there was an increase in expenditures of $1.7 million related to preliminary surveys, plans, and investigations (primarily for the Holcomb project).

Equity and Liabilities

Patronage capital equity increased $7.6 million to $959.7 million as of June 30, 2016 compared to $952.1 million as of December 31, 2015. The increase was primarily due to a margin attributable to us of $20.1 million for the six months ended June 30, 2016 partially offset by the $12.5 million that we retired in connection with KCEC's withdrawal from membership in us.

Long-term debt decreased $120.5 million, or 3.7 percent, to $3.153 billion as of June 30, 2016 compared to $3.274 billion as of December 31, 2015 and current maturities of long-term debt increased $18.7 million, or 20.4 percent, to $110.1 million as of June 30, 2016 compared to $91.4 million as of December 31, 2015. The total decrease of $101.8 million was primarily due to debt payments of $408.6 million (primarily $333.0 million for the Revolving Credit Agreement, $37.0 million for the Springerville certificates, $27.1 million for the First Mortgage Obligation, Series

2009C and $4.5 million for the Colowyo Bonds) partially offset by debt proceeds of $310.0 million (primarily $248.0 million from the Series 2016A Bonds which were issued in May 2016 and $62.0 million from the Revolving Credit Agreement). Long-term debt was also impacted by $2.8 million of debt issuance costs related to the May 2016 issuance of the Series 2016A Bonds. Debt issuance costs are accounted for as a direct deduction of the associated long-term debt carrying amount consistent with the accounting for debt discounts and premiums. The $2.8 million of debt issuance costs will be amortized to interest expense using an effective interest method over the life of the 30-year term of the Series 2016A Bonds.

Short-term borrowings consist of our commercial paper program that we established in May 2016 to provide an additional financing source for our short-term liquidity needs. Short-term borrowings increased $94.9 million as of June 30, 2016 compared to $0 as of December 31, 2015. The increase was due to $234.9 million of net proceeds from issuances of commercial paper partially offset by $140.0 million of commercial paper payments (maturities).

Accrued property taxes decreased $9.4 million, or 34.4 percent, to $18.0 million as of June 30, 2016 compared to $27.4 million as of December 31, 2015. The decrease was primarily due to $24.3 million of property tax payments during 2016 (of which $15.5 million were paid during the second quarter of 2016) partially offset by accruals for property taxes due in future periods.

Regulatory liabilities increased $47.7 million, or 106 percent, to $92.7 million as of June 30, 2016 compared to $45.0 million as of December 31, 2015. The increase was primarily due to the deferral of the recognition of $47.6 million of other income in connection with the June 30, 2016 withdrawal of KCEC from membership in us.

Asset retirement obligations increased $5.3 million, or 9.6 percent, to $60.5 million as of June 30, 2016 compared to $55.2 million as of December 31, 2015. The increase was primarily due to additions of $5.5 million related to waste impoundment ponds in Colorado.

Other deferred credits increased $9.5 million, or 16.6 percent, to $66.9 million as of June 30, 2016 compared to $57.4 million as of December 31, 2015. The increase was primarily due to the deferral of the unrealized loss related to the change in fair value of interest rate swaps of $12.6 million and a $2.3 million refund from Tucson Electric Power Company, or TEP, required by the Federal Energy Regulatory Commission, or FERC, for transmission service agreements. TEP has appealed the FERC order and has stated that the funds are subject to refund in the event TEP is ultimately successful in its appeal. Due to uncertainties regarding the ultimate outcome of this matter, we did not recognize benefit of the receipt of the $2.3 million. The funds are therefore recorded in other deferred credits.

Liquidity

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of debt. As of June 30, 2016, we had $158.8 million in cash and cash equivalents. Our committed credit arrangement as of June 30, 2016 is as follows (dollars in thousands):

	Authorized Amount	Available June 30 2016
Revolving Credit Agreement	$ 750,000 (1)	$ 702,258 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) Of the portion of this facility that was unavailable at June 30, 2016, $47.7 million was related to a letter of credit issued to support variable rate demand bonds.

Our Revolving Credit Agreement has aggregate commitments of $750 million which includes a swingline sublimit of $100 million, a letter of credit sublimit of $200 million, and a commercial paper sublimit of $500 million, of which $100 million of the swingline sublimit, $152 million of the letter of credit sublimit, and $405.1 million of the commercial paper sublimit remained available as of June 30, 2016. The Revolving Credit Agreement is secured under the Master Indenture and has a term extending through July 26, 2019. We had no outstanding borrowings at

June 30, 2016 and $271 million at December 31, 2015 and an issued letter of credit for the Moffat County, CO Pollution Control Bonds in the principal amount of $46.8 million plus accrued interest supported by the Revolving Credit Agreement. Funds advanced under the Revolving Credit Agreement bear interest either at a Eurodollar rate or a base rate, at our option. The Eurodollar rate is the LIBOR rate for the term of the advance plus a margin (currently 1.00%) based on our credit ratings. The base rate is the highest of (a) the federal funds rate plus ½ of 1.00%, (b) the Bank of America prime rate, and (c) the one-month LIBOR rate plus 1.00% and plus a margin (currently 0%) based on our credit ratings. As of June 30, 2016, we have $702 million in availability under the Revolving Credit Agreement.

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

Under our commercial paper program, which we began in May 2016, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper sublimit under our Revolving Credit Agreement, which is the lesser of $500 million or the amount available under the Revolving Credit Agreement thereby providing 100% dedicated support for any commercial paper outstanding. We had $94.9 million of commercial paper outstanding at June 30, 2016.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the Revolving Credit Agreement.

Cash Flow

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

June 30, 2016 compared to June 30, 2015

Operating activities. Net cash provided by operating activities was $132.2 million for the six months ended June 30, 2016 comprised primarily of net margins of $20.3 million, non-cash depreciation, amortization, and depletion of $80.8 million, other non-cash amortization of $7.3 million and an increase in cash collected from Member accounts receivable resulting from increased loads. Operating activities were also impacted by a decrease in accrued property taxes related to the timing of the payments related to certain obligations that are due during the second quarter of 2016 and the receipt of $49.5 million of cash related to the withdrawal of KCEC from membership in us.

Investing activities. Net cash used in investing activities was $101.3 million for the six months ended June 30, 2016 comprised primarily of capital expenditures for generation and transmission improvements and system upgrades.

Financing activities. Net cash used in financing activities was $16.7 million for the six months ended months June 30, 2016 comprised primarily of long-term debt payments of $408.6 million (principally $333.0 million on our Revolving Credit Agreement, $27.1 million on the First Mortgage Obligations, Series 2009C, $37.0 million on the Springerville certificates and $4.5 million on the Colowyo Bonds) partially offset by debt proceeds of $248.0 million on the Series 2016A Bonds. Also we had $234.9 million of net proceeds related to issuances of commercial paper which was partially offset by $140.0 million of commercial paper payments (maturities). In June 2016, we retired $12.5 million of patronage capital related to the withdrawal of KCEC from membership in us.

Capital Expenditures

We forecast our capital expenditures annually as part of our long-term planning. We regularly review these projections to update our calculations to reflect changes in our future plans, facility costs, market factors and other items affecting our forecasts. Without taking into account the Clean Power Plan, in the years 2016 through 2020, we estimate that we may invest approximately $1.4 billion in new facilities and upgrades to our existing facilities.

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

The majority of our capital expenditures consist of additions to electric plant and equipment. Other capital projects include several transmission projects, such as expansion in the Interstate 25 corridor north of Denver, construction of the Southwest Colorado Transmission Reliability Project, and additional projects to improve reliability and load-serving capability throughout our service area. As of June 30, 2016, we have incurred capital expenditures of approximately $89.1 million, excluding land and water purchases, in connection with the expansion project of an existing coal-fired generating station called Holcomb Generating Station, which we refer to as Holcomb. Additional capital expenditures for Holcomb are not included in our current capital expenditure projections as our Board has not yet made a decision to proceed with the construction of this project including our option to acquire the development rights.

Contractual Commitments

Indebtedness. As of June 30, 2016, we had approximately $2.8 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 National Rural Utilities Cooperative Finance Corporation and CoBank, ACB (with the exception of two unsecured notes), the First Mortgage Obligations, Series 2009C, the First Mortgage Bonds, Series 2010A, the First Mortgage Obligations, Series 2014B, the First Mortgage Bonds, Series 2014E-1 and E-2, the Series 2016A Bonds, and the pollution control revenue bonds. Substantially all of our assets are pledged as collateral under the Master Indenture. The Springerville certificates are secured only by a mortgage and lien on Springerville Generating Station Unit 3 and the Springerville lease.

On May 23, 2016, we issued our Series 2016A Bonds in an unregistered offering pursuant to Rule 144A under the Securities Act of 1933 with an aggregate principal amount of $250 million. The Series 2016A Bonds mature on June 1, 2046 and bear interest at a rate of 4.25 percent per annum. We utilized the proceeds from the Series 2016A Bonds primarily to repay outstanding indebtedness under the Revolving Credit Agreement. In connection with the Series 2016A Bonds, we entered into an exchange and registration rights agreement pursuant to which we agreed to file a registration statement relating to an exchange offer for our Series 2016A Bonds. On June 27, 2016, we commenced an offer to exchange all of the unregistered $250 million aggregate principal amount of the Series 2016A Bonds for $250 million aggregate principal amount of registered Series 2016A Bonds. We completed the exchange offer in July 2016 which satisfied our obligations under the exchange and registration rights agreement. The exchange offer did not represent a new financing transaction and there were no proceeds to us when the exchange offer was completed.

Operating Lease Obligations. We have a 10-year power purchase agreement with AltaGas Brush Energy, Inc. to toll natural gas at the Brush Generating Station for 70 MWs which began on October 1, 2009. We account for this power purchase agreement as an operating lease because it conveys to us the right to use power generating equipment for a stated period of time.

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

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

Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, including greenhouse gases, water quality, and other environmental matters. These environmental laws, rules and regulations are complex, change frequently and have become more stringent and numerous over time. The following are some of the recent developments relating to environmental regulations and litigation that may impact us.

Clean Power Plan. In 2014, the Environmental Protection Agency, or EPA, proposed emission limits and emission guidelines of carbon dioxide for existing generating facilities in a comprehensive proposed rule referred to as the "Clean Power Plan." On August 3, 2015, the EPA issued a pre-publication version of a final rule regarding emissions of carbon dioxide from certain fossil fuel-fired electric generating units. On October 23, 2015, the final rule was published in the Federal Register. Currently, approximately 25 percent of our energy to our Members is served with non-carbon emitting resources and our existing generating facilities generate approximately 63 percent of our energy resources, a substantial percentage of which is generated by coal-fired facilities. Emissions of carbon dioxide from our plants totaled approximately 13.0 million short tons in 2015. The Clean Power Plan establishes guidelines for states to develop plans to limit emissions of carbon dioxide from existing units. The goal of the rule is a reduction in carbon dioxide emissions from 2005 levels of 32 percent nationwide by 2030 and specifies interim emission rates phasing in between 2022 and 2029. At this time it is not possible to understand how we will be impacted (financially or operationally) in each state, as that information will be developed in state specific plans that will be submitted to the EPA by September 2016. The EPA will take a year to review and approve state plans. States may request an extension of two additional years. However, the United States Supreme Court issued a stay of the Clean Power Plan on February 9, 2016, as such, the 2016 date is delayed and the other dates are anticipated to be delayed as well. If the rule is upheld by the courts, states must implement their plan to ensure power plants achieve the interim carbon dioxide emissions performance goals. The final state goals for carbon dioxide emissions per MWh in year 2030 and beyond under the Clean Power Plan for the five states where we would be impacted are as follows: Arizona—1,031 lb/MWh; Colorado—1,174 lb/MWh; Nebraska—1,296 lb/MWh; New Mexico—1,146 lb/MWh; and Wyoming—1,299 lb/MWh. Each of these goals is substantially below the carbon dioxide emission rate of a well-designed coal-fired unit and assumes increased reliance on a combination of natural gas-fired and renewable energy sources, with coal-fired generation being dispatched less often or curtailed entirely. As of June 30, 2016, Nebraska, New Mexico, and Wyoming have stopped all work on the Clean Power Plan until litigation is completed. Arizona has stopped work on modeling and plan development, but is continuing meeting on a quarterly basis. Colorado has announced they are not developing a plan to submit to EPA but do plan to continue working on a carbon reduction plan, however, it is not clear at this time what they will actually be doing. The Clean Power Plan is the most complex and wide-ranging regulation under the Clean Air Act. We, along with 24 states, other utilities and national trade organizations, filed motions to stay the Clean Power Plan with the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit Court of Appeals. On January 21, 2016, the D.C. Circuit Court of Appeals denied the motions to stay the Clean Power Plan, but ordered an expedited briefing schedule and scheduled oral arguments for June 2, 2016. We, along with 27 states, including Arizona, Colorado, Nebraska and Wyoming, other utilities and national trade organizations, filed applications for immediate stay of the Clean Power Plan with the United States Supreme Court. On February 9, 2016, the Supreme Court stayed the Clean Power Plan pending judicial review. On May 16, 2016, the D.C. Circuit Court of Appeals issued an order, on its own motion, rescheduling the oral arguments in the case from June 2, 2016 to September 27, 2016 before an en banc court. The impacts of the final rule and any subsequent challenges cannot be determined at this time; however if the court upholds the final rule, it could have a material impact on our operations, including increased operating costs, additional investment in new generation (natural gas and renewables) and transmission, investment in energy efficiency programs and decreased operation, or closure of coal-fired plants.

For further discussion regarding potential effects on our business from environmental regulations, see "Item 1 – BUSINESS — ENVIRONMENTAL REGULATION" and "Item 1A — Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2015.

Rating Triggers

Our current senior secured ratings are "A3 (stable outlook)" by Moody's Investors Services, "A (stable outlook)" by Standard & Poor's Ratings Services, and "A (stable outlook)" by Fitch Rating Inc.

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

We currently have contracts that require adequate assurance of performance. These include power sales arrangements that are required to be accounted for as operating leases, natural gas supply contracts and financial risk management contracts. Some of the contracts are directly tied to our credit rating being maintained at "BBB-" or better from S&P or "Baa3" from Moody's. We expect to enter into additional natural gas supply contracts and/or risk management contracts which will contain similar adequate assurance requirements. If we are required to provide such adequate assurances, we do not believe the amounts will be significant or that they will have a material adverse effect on our financial condition or our future results of operations.

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

We have a 10-year purchase power agreement with AltaGas Brush Energy, Inc. to toll natural gas at the Brush Generating Station for 70 MWs which began on October 1, 2009. We account for this power purchase agreement as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have not been any material changes to market risks during the most recent fiscal quarter from those reported in our Annual Report on Form 10-K for the year ended December 31, 2015.

Interest Rate Risk

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures for new facilities and upgrades to our existing facilities. To mitigate the risk of rising interest rates, we have entered into interest rate swaps to hedge a portion of our long-term debt interest rate exposure.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Controls

There have been no changes in our internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information required by this Item is contained in the Notes to Unaudited Consolidated Financial Statements within Part I of this Form 10-Q in Note 12 - Legal.

Item 4. Mine Safety Disclosures

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

Item 6. Exhibits

Exhibit Number	Description of Exhibit
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Micheal S. McInnes (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Patrick L. Bridges (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Micheal S. McInnes (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Patrick L. Bridges (Principal Financial Officer).
95	Mine Safety Disclosure Exhibit.
101	XBRL Interactive Data File.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Tri-State Generation and Transmission Association, Inc.

Date: August 9, 2016

By: /s/ Micheal S. McInnes
Micheal S. McInnes
Chief Executive Officer

Date: August 9, 2016

/s/ Patrick L. Bridges
Patrick L. Bridges
Senior Vice President/Chief Financial Officer
(Principal Financial Officer)