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 September 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** ☐

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 SEPTEMBER 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)

	September 30, 2016	December 31, 2015
ASSETS	(unaudited)	
Property, plant and equipment		
Electric plant		
In service	$ 5,651,861	$ 5,486,518
Construction work in progress	192,249	216,279
Total electric plant	5,844,110	5,702,797
Less allowances for depreciation and amortization	(2,334,682)	(2,240,732)
Net electric plant	3,509,428	3,462,065
Other plant	232,928	227,957
Less allowances for depreciation, amortization and depletion	(84,368)	(73,471)
Net other plant	148,560	154,486
Total property, plant and equipment	3,657,988	3,616,551
Other assets and investments		
Investments in other associations	125,080	123,686
Investments in and advances to coal mines	17,059	16,221
Restricted cash and investments	1,000	1,000
Intangible assets	20,141	25,634
Other noncurrent assets	12,660	12,139
Total other assets and investments	175,940	178,680
Current assets		
Cash and cash equivalents	167,232	144,587
Restricted cash and investments	4,730	9,530
Deposits and advances	31,467	21,673
Accounts receivable—Members	89,739	106,216
Other accounts receivable	19,480	14,270
Coal inventory	58,544	59,277
Materials and supplies	88,903	85,501
Total current assets	460,095	441,054
Deferred charges		
Regulatory assets	413,700	415,081
Prepayment—NRECA Retirement Security Plan	45,006	49,146
Other	128,721	122,535
Total deferred charges	587,427	586,762
Total assets	**$ 4,881,450**	**$ 4,823,047**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 977,425	$ 952,082
Accumulated other comprehensive income	556	589
Noncontrolling interest	109,011	108,757
Total equity	1,086,992	1,061,428
Long-term debt	3,144,770	3,273,538
Total capitalization	4,231,762	4,334,966
Current liabilities		
Member advances	9,601	9,403
Accounts payable	82,586	96,098
Short-term borrowings	74,951	—
Accrued expenses	28,583	30,045
Accrued interest	51,914	34,332
Accrued property taxes	26,652	27,395
Current maturities of long-term debt	110,289	91,419
Total current liabilities	384,576	288,692
Deferred credits and other liabilities		
Regulatory liabilities	92,572	45,000
Deferred income tax liability	26,242	28,629
Intangible liabilities	4,159	6,221
Asset retirement obligations	64,009	55,215
Other	70,852	57,423
Total deferred credits and other liabilities	257,834	192,488
Accumulated postretirement benefit and postemployment obligations	7,278	6,901
Total equity and liabilities	**$ 4,881,450**	**$ 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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Operating revenues				
Member electric sales	$ 326,251	$ 334,009	$ 873,537	$ 858,840
Non-member electric sales	35,478	30,394	92,266	95,242
Other	23,062	23,699	64,684	68,324
	384,791	388,102	1,030,487	1,022,406
Operating expenses				
Purchased power	105,751	91,001	254,956	235,422
Fuel	67,839	65,586	180,389	162,430
Production	51,699	55,485	159,697	179,382
Transmission	41,383	39,851	116,975	114,922
General and administrative	6,463	5,421	17,965	17,044
Depreciation, amortization and depletion	45,314	38,371	126,090	109,317
Coal mining	10,174	7,096	25,845	23,039
Other	3,969	3,879	12,989	11,504
	332,592	306,690	894,906	853,060
Operating margins	**52,199**	**81,412**	**135,581**	**169,346**
Other income				
Interest income	1,094	1,071	3,227	3,241
Capital credits from cooperatives	1,105	754	5,800	5,995
Other income	864	808	2,599	2,659
	3,063	2,633	11,626	11,895
Interest expense, net of amounts capitalized	37,041	35,846	108,385	106,919
Income taxes	350	—	700	—
Net margins including noncontrolling interest	17,871	48,199	38,122	74,322
Net (income) loss attributable to noncontrolling interest	(132)	103	(313)	390
Net margins attributable to the Association	**$ 17,739**	**$ 48,302**	**$ 37,809**	**$ 74,712**

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 September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Net margins including noncontrolling interest	$ 17,871	$ 48,199	$ 38,122	$ 74,322
Other comprehensive income (loss):				
Unrealized gain (loss) on securities available for sale	36	(89)	35	(112)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(23)	9	(68)	26
Income tax expense related to components of other comprehensive income (loss)	—	—	—	—
Other comprehensive income (loss)	13	(80)	(33)	(86)
Comprehensive income including noncontrolling interest	17,884	48,119	38,089	74,236
Net comprehensive (income) loss attributable to noncontrolling interest	(132)	103	(313)	390
Comprehensive income attributable to the Association	**$ 17,752**	**$ 48,222**	**$ 37,776**	**$ 74,626**

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)

	Nine Months Ended September 30,	
	2016	**2015**
Patronage capital equity at beginning of period	$ 952,082	$ 908,669
Net margins attributable to the Association	37,809	74,712
Retirement of patronage capital	(12,466)	—
Patronage capital equity at end of period	**977,425**	**983,381**
Accumulated other comprehensive income (loss) at beginning of period	589	(828)
Unrealized gain (loss) on securities available for sale	35	(112)
Reclassification adjustment for actuarial (gain) loss on postretirement benefit obligation included in net income	(68)	26
Accumulated other comprehensive income (loss) at end of period	**556**	**(914)**
Noncontrolling interest at beginning of period	108,757	109,302
Net income (loss) attributable to noncontrolling interest	313	(390)
Equity distribution to noncontrolling interest	(59)	(57)
Noncontrolling interest at end of period	**109,011**	**108,855**
Total equity at end of period	**$ 1,086,992**	**$ 1,091,322**

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)

	Nine Months Ended September 30,	
	2016	**2015**
Operating activities		
Net margins including noncontrolling interest	$ 38,122	$ 74,322
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	126,090	109,317
Amortization of intangible asset	5,493	5,493
Amortization of NRECA Retirement Security Plan prepayment	4,029	4,140
Amortization of debt issuance costs	1,436	1,400
Deferred membership withdrawal income	47,572	—
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(2,546)	(3,698)
Change in restricted cash and investments	(121)	29,148
Changes in operating assets and liabilities:		
Accounts receivable	(865)	21,026
Coal inventory	733	(29,170)
Materials and supplies	(3,402)	(4,132)
Accounts payable and accrued expenses	(4,360)	(10,845)
Accrued interest	17,582	16,565
Accrued property taxes	(744)	(112)
Other deferred credits - BNSF settlement	—	(29,381)
Other	(2,471)	11,084
Net cash provided by operating activities	**226,548**	**195,157**
Investing activities		
Purchases of plant	(150,336)	(217,929)
Changes in deferred charges	(7,390)	1,495
Proceeds from other investments	313	407
Net cash used in investing activities	**(157,413)**	**(216,027)**
Financing activities		
Changes in Member advances	(980)	(5,134)
Payments of long-term debt	(416,532)	(101,772)
Proceeds from issuance of debt	307,000	230,185
Increase in short-term borrowings, net	74,951	—
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	**(46,490)**	**123,611**
Net increase in cash and cash equivalents	**22,645**	**102,741**
Cash and cash equivalents – beginning	**144,587**	**92,468**
Cash and cash equivalents – ending	**$ 167,232**	**$ 195,209**
Supplemental cash flow information:		
Cash paid for interest	$ 101,066	$ 101,480
Cash paid for income taxes	$ 700	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ (4,974)	$ (1,152)

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 Nine Months Ended September 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 nine months ended September 30, 2016 and 2015 are not necessarily indicative of the results that may be expected for an entire year or any other period.

On September 1, 2016, we announced that the owners of Craig Generating Station Unit 1 reached an agreement with the Colorado Department of Public Health and Environment, U.S. Environmental Protection Agency, WildEarth Guardians and the National Parks Conservation Association to revise the Colorado Visibility and Regional Haze State Implementation Plan ("SIP"). Under the proposed revision to the SIP, the 427-megawatt Craig Generating Station Unit 1, which is part of a three-unit, coal-fired generating facility in Craig, Colorado, will be retired by December 31, 2025. The retirement date was previously estimated to be December 31, 2051. We are the operator of Craig Generating Station and own 24 percent of Craig Generating Station Unit 1. Craig Generating Station Unit 2 and Unit 3 will continue to operate. Our share of Craig Generating Station Unit 1 is 102 megawatts with a net book value of $28.6 million as of September 30, 2016. The shortened life increased monthly depreciation expense in the amount of $186,000 beginning September 1, 2016.

As part of the above mentioned agreement on proposed revisions to the SIP, we intend to retire the Nucla Generating Station by December 31, 2022. The retirement date was previously estimated to be December 31, 2049. We are the operator and sole owner of the 100 megawatt, coal-fired Nucla Generating Station with a net book value of $62.8 million as of September 30, 2016. The shortened life increased monthly depreciation expense in the amount of $666,000 beginning September 1, 2016 and increased the asset retirement obligation in the amount of $2.8 million as of September 30, 2016. The New Horizon Mine, which supplies coal to Nucla Generating Station, will cease coal production with the retirement of Nucla Generating Station. Reclamation efforts at the New Horizon Mine will continue.

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 other 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 other operating expenses is included in our consolidated financial statements.

Our share in each jointly owned facility is as follows as of September 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 %	$ 345,104	$ 231,067	$ 36,420
MBPP - Laramie River Station	24.13 %	399,374	292,476	13,370
San Juan Project – San Juan Unit 3	8.20 %	82,688	69,290	—
Total		$ 827,166	$ 592,833	$ 49,790

NOTE 2 – ACCOUNTING FOR RATE REGULATION

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

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

	September 30, 2016	December 31, 2015
Regulatory assets		
Deferred income tax expense (1)	$ 26,242	$ 28,629
Deferred prepaid lease expense- Craig 3 Lease (2)	11,328	16,183
Deferred prepaid lease expense- Springerville 3 Lease (3)	91,160	92,878
Goodwill – J.M. Shafer (4)	58,404	60,541
Goodwill – Colowyo Coal (5)	40,552	41,327
Deferred debt prepayment transaction costs (6)	168,973	175,444
Interest rate swaps (7)	17,041	—
Other	—	79
Total regulatory assets	413,700	415,081
Regulatory liabilities		
Deferred revenues (8)	45,000	45,000
Membership withdrawal (9)	47,572	—
Total regulatory liabilities	92,572	45,000
Net regulatory asset	$ 321,128	$ 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, amortization and depletion 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,

amortization and depletion expense in the amount of $2.3 million annually through the 47-year period ending in 2056 and recovered from our Members in rates.

(4) Represents goodwill related to our acquisition of Thermo Cogeneration Partnership, LP ("TCP") in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $2.8 million annually through the 25-year period ending in 2036 and recovered from our Members in rates.

(5) Represents goodwill related to our acquisition of Colowyo Coal Company LP ("Colowyo Coal") in December 2011. Goodwill is being amortized to depreciation, amortization and depletion expense in the amount of $1.0 million annually through the 44-year period ending in 2056 and recovered from our Members in rates.

(6) Represents transaction costs that we incurred related to the prepayment of our long-term debt in 2014. These costs are being amortized to depreciation, amortization and depletion expense in the amount of $8.6 million annually over the 21.4-year average life of the new debt issued and recovered from our Members in rates.

(7) Represents deferral of the 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 Kit Carson Electric Cooperative, Inc. ("KCEC") 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 consisted 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. This deferred membership withdrawal income will be refunded to Members through reduced rates when recognized in other income in future periods.

NOTE 3 – INVESTMENTS IN OTHER ASSOCIATIONS

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

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 our consolidated statements of financial position. The other funds are for funds restricted by contract or other legal reasons that are expected to be settled beyond one year. These funds are classified as noncurrent and are included in other assets and investments on our consolidated statements of financial position.

We 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 September 30, 2016, the entire $3.7 million balance of the defeasance investment is for Colowyo Bond debt payments due within one year and is, therefore, a current asset on our consolidated statements of financial position. The Colowyo Bonds mature in November 2016.

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

	September 30, 2016	December 31, 2015
Investments in securities pledged as collateral	$ 3,749	$ 8,671
Funds restricted by contract	981	859
Restricted cash and investments - current	4,730	9,530
Funds restricted by contract	1,000	1,000
Restricted cash and investments - noncurrent	1,000	1,000
Total restricted cash and investments	$ 5,730	$ 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. Included in other deferred charges were preliminary surveys and investigations of $110.2 million and $107.1 million as of September 30, 2016 and December 31, 2015, respectively. These amounts were primarily comprised of expenditures for the Holcomb Station Project of $90.3 million and $86.7 million as of September 30, 2016 and December 31, 2015, respectively.

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. Included in other deferred charges were advance payments of $19.1 million and $11.5 million as of September 30, 2016 and December 31, 2015, respectively.

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 $50.9 million as of September 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 September 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.

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):

	September 30, 2016	December 31, 2015
Total debt	$ 3,267,146	$ 3,371,679
Less debt issuance costs	(22,751)	(21,201)
Less debt discounts	(10,619)	(8,739)
Plus debt premiums	21,283	23,218
Total debt adjusted for discounts, premiums and debt issuance costs	3,255,059	3,364,957
Less current maturities	(110,289)	(91,419)
Long-term debt	$ 3,144,770	$ 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 our consolidated statements of financial position.

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

	September 30, 2016	December 31, 2015
Commercial paper outstanding, net of discounts	$ 74,951	$ —
Weighted average interest rate	0.73 %	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):

	September 30, 2016	December 31, 2015
Asset retirement obligation at beginning of period	$ 55,215	$ 53,754
Liabilities incurred	5,453	1,802
Liabilities settled	(1,069)	(3,028)
Accretion expense	2,113	3,324
Change in cash flow estimate	2,297	(637)
Asset retirement obligation at end of period	$ 64,009	$ 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. Our consolidated statements of operations include income tax expense of $350,000 for the three months ended September 30, 2016 and no income tax expense or benefit for the comparable period in 2015. Income tax expense was $700,000 for the nine months ended September 30, 2016 and there was no income tax expense or benefit for the comparable period in 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 measurement 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 September 30, 2016		As of December 31, 2015	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Marketable securities	$ 886	$ 1,050	$ 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 $40.0 million as of September 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 borrowing rates for similar types of borrowing arrangements. These valuation assumptions utilize observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs). The principal amounts and fair values of our debt are as follows (dollars in thousands):

	As of September 30, 2016		As of December 31, 2015	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,267,146	$ 3,719,629	$ 3,371,679	$ 3,616,946

Interest Rate Swaps

We entered into forward starting interest rate swaps in 2016 to hedge a portion of our future long-term debt interest rate expense. See Note 6 – Long-Term Debt. These interest rate swaps are derivative instruments in accordance with ASC 815, *Derivatives and Hedging,* and are recorded at fair value on a recurring basis. The estimated fair value of these interest rate swaps utilizes observable inputs based on market data obtained from independent sources and are therefore considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs) and are included in other deferred credits and other liabilities on our consolidated statements of financial position. At September 30, 2016, the fair value of our interest rate swaps was an unrealized loss of $17.0 million, which was deferred in accordance with our regulatory accounting. See Note 2 – Accounting for Rate Regulation.

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 $837.5 million and $853.3 million at September 30, 2016 and December 31, 2015, respectively, the long-term debt of $472.6 million and $511.0 million at September 30, 2016 and December 31, 2015, respectively, accrued interest associated with the long-term debt of $5.4 million and $14.3 million at September 30, 2016 and December 31, 2015, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $109.0 million and $108.8 million at September 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 September 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 September 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 $15.8 million for the nine months ended September 30, 2016 and the comparable period in 2015. Our consolidated statements of operations also include interest expense of $22.8 million for the nine months ended September 30, 2016 and $24.3 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 $2.1 million at September 30, 2016 and $2.3 million at December 31, 2015, 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 $14.4 million at September 30, 2016 and $14.1 million at December 31, 2015 and is recorded within investments in and advances to coal mines.

NOTE 12 – LEGAL

There are no new material litigation or proceedings pending or threatened against us or any material developments in any material existing pending litigation or proceedings.

For further discussion regarding legal proceedings, see our Annual Report on Form 10-K for the year ended December 31, 2015 "Item 8 – FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA – Notes to Consolidated Financial Statements – Note 12-Commiments and Contingencies – Legal."

NOTE 13 – NEW ACCOUNTING PRONOUNCEMENTS

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-15, *Statement of Cash Flows (Topic 230) – Classification of Certain Cash Receipts and Payments.* This amendment provides specific guidance on certain cash flow presentation and classification issues in order to reduce diversity in practice on the statement of cash flows. The issues that primarily relate to us are the classification of proceeds from the settlement of insurance claims and distributions received from equity method investees. This amendment is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted. The guidance is applied using a full retrospective transition method. We are currently evaluating the impact that this amendment will have on our statement of cash flows.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* This amendment requires a lessee to recognize substantially all leases (whether operating or finance leases) on the balance sheet as a right-of-use asset and an associated lease liability. 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*. This amendment requires an entity to measure investments in equity securities, except those that result in consolidation or are accounted for under the equity method of accounting, at fair value with changes in fair value recognized in net income. For equity investments that do not have readily determinable fair value and don't qualify for the existing practical expedient in ASC 820, *Fair Value Measurements*, to estimate fair value using the net asset value per share of the investment, the guidance provides a new measurement alternative. Entities may choose to measure those investments at cost, less any impairment, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investment of the same issuer. This amendment also affects financial liabilities using the fair value option and the presentation and disclosure requirements for financial instruments. Also, an entity should present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The amendments are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early application by public business entities to financial statements of fiscal years or interim periods that have not yet been issued or, by all other entities, that have not yet been made available for issuance are permitted as of the beginning of the fiscal year of adoption. An entity should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments related to equity securities without readily determinable fair values (including disclosure requirements) should be applied prospectively to equity investments that exist as of the date of adoption of the update. We are currently evaluating the impact of this amendment on our 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 the annual period ending after December 15, 2016. The adoption of this update is not expected to have a material impact on our 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, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* which deferred the effective date of the new revenue standard by one year. The core principle under the new revenue standard requires that revenue should be recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. To achieve the core principle, the following steps are required: (1) identify the contract(s) with the customer, (2) identify the performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to the performance obligations in the contract, and (5) recognize revenue when (or as) the entity satisfies a performance obligation. This 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 do not plan to early adopt the new revenue standard. 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 our regions 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 September 30, 2016, our Members served approximately 600,000 retail electric meters over a nearly 200,000 square-mile area. We sold 14.0 million megawatt hours, or MWhs, for the nine months ended September 30, 2016, of which 85.7 percent was to Members. Total revenue from electric sales was $965.8 million for the nine months ended September 30, 2016, of which 90.4 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 95.5 percent of our revenue from Member sales for the nine months ended September 30, 2016) and extending through 2040 for the remaining Member (Delta Montrose Electric Association) 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 September 30, 2016, 18 Members have enrolled in this program with capacity totaling approximately 113 megawatts.

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.

Recent Developments

On September 1, 2016, we announced that the owners of Craig Generating Station Unit 1 reached an agreement with the Colorado Department of Public Health and Environment, U.S. Environmental Protection Agency, or EPA, WildEarth Guardians and the National Parks Conservation Association to revise the Colorado Visibility and Regional Haze State Implementation Plan, or SIP. Under the proposed revision to the SIP, the 427-megawatt Craig Generating Station Unit 1, which is part of a three-unit, coal-fired generating facility in Craig, Colorado, will be retired by December 31, 2025. The retirement date was previously estimated to be December 31, 2051. We are the operator of Craig Generating Station and own 24 percent of Craig Generating Station Unit 1. Craig Generating Station Unit 2 and Unit 3 will continue to operate. Our share of Craig Generating Station Unit 1 is 102 megawatts with a net book value of $28.6 million as of September 30, 2016. The shortened life increased monthly depreciation expense in the amount of $186,000 beginning September 1, 2016.

As part of the above mentioned agreement on proposed revisions to the SIP, as previously disclosed, we intend to retire the Nucla Generating Station by December 31, 2022. The retirement date was previously estimated to be December 31, 2049. We are the operator and sole owner of the 100 megawatt, coal-fired Nucla Generating Station with a net book value of $62.8 million as of September 30, 2016. The shortened life increased monthly depreciation expense in the amount of $666,000 beginning September 1, 2016 and increased the asset retirement obligation in the amount of $2.8 million as of September 30, 2016. The New Horizon Mine, which supplies coal to Nucla Generating Station, will cease coal production with the retirement of Nucla Generating Station. Reclamation efforts at the New Horizon Mine will continue.

Under the federal regional haze regulations, the State of Colorado develops and implements a SIP to address visibility in national parks and wilderness areas. Colorado's plan requires reductions of NOx emissions from generation sources. Several procedural steps are required to implement the terms of the agreement, including approval by the Colorado Air Quality Control Commission, the state legislature and the EPA. A rulemaking hearing regarding the SIP and this agreement is currently scheduled with the Colorado Air Quality Control Commission for December 15, 2016.

Summary of Critical Accounting Policies

As of September 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 of Directors, or 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 September 30, 2016, patronage capital equity was $977.4 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(s). 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 two demand rates (a generation demand and a transmission/delivery demand) that are both billed on the Member's highest thirty-minute integrated total demand measured in each monthly billing period during our peak period from noon to 10:00 pm daily, Monday through Saturday, with the exception of six holidays. 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.

Approved by our Board in September 2016 and effective January 1, 2017, we will be implementing a new rate schedule (A-40). The new A-40 rate schedule uses the same rate design as the A-39 rate, but increases the average budgeted Member cents/kWh for 2017 by 4.23 percent compared to the average budgeted Member cents/kWh for 2016.

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 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. On September 20, 2016, we gave notice, as required by New Mexico law, to the NMPRC of our 2017 wholesale rate which is scheduled to become effective on January 1, 2017, or the A-40 rate. No New Mexico Member filed a protest with the NMPRC of the A-40 rate and thus the A-40 rate will become effective on January 1, 2017 without NMPRC review or approval.

Master Indenture

As of September 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 September 30, 2016 compared to three months ended September 30, 2015

Operating Revenues

Member electric sales decreased 109,143 MWhs to 4,426,677 MWhs for the three months ended September 30, 2016 compared to 4,535,820 MWhs for the same period in 2015. The decrease in MWhs sold in 2016 resulted in a decrease of $7.7 million in Member electric sales revenue to $326.3 million for the three months ended September 30, 2016 compared to $334.0 million for the same period in 2015.

Non-member electric sales increased 212,278 MWhs, or 33.6 percent, to 843,965 MWhs for the three months ended September 30, 2016 compared to 631,687 MWhs for the same period in 2015. Non-member electric sales revenue increased $5.1 million, or 16.8 percent, to $35.5 million for the three months ended September 30, 2016 compared to $30.4 million for the same period in 2015. The increase in non-member electric sales revenue was due to higher non-member long-term firm sales of 102,041 MWhs with revenue of $3.8 million (primarily due to a new power sales arrangement beginning June 2016) and higher non-member short-term sales of 110,237 MWhs with revenue of $1.3 million.

Operating Expenses

Purchased power increased 256,779 MWhs, or 12.8 percent, to 2,256,223 MWhs for the three months ended September 30, 2016 compared to 1,999,444 MWhs for the same period in 2015. Purchased power expense increased $14.8 million, or 16.3 percent, to $105.8 million for the three months ended September 30, 2016 compared to $91.0 million for the same period in 2015 due to the increase in MWhs purchased (primarily due to a new power purchase arrangement beginning June 2016) and a 3.2 percent increase in the average cost per MWh of purchased power.

Depreciation, amortization and depletion expense increased $6.9 million, or 18.0 percent, to $45.3 million for the three months ended September 30, 2016 compared to $38.4 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 September 1, 2016) as a result of shortening the life of Craig Generating Station Unit 1 (a monthly increase of $186,000) and Nucla Generating Station (a monthly increase of $666,000).

Nine months ended September 30, 2016 compared to nine months ended September 30, 2015

Operating Revenues

Member electric sales increased 81,851 MWhs to 12,026,377 MWhs for the nine months ended September 30, 2016 compared to 11,944,526 MWhs for the same period in 2015. The increase in MWhs sold in 2016 and the effect of the increased rates paid by our Members in 2016 compared to 2015 resulted in an increase of $14.7 million in Member electric sales revenue to $873.5 million for the nine months ended September 30, 2016 compared to $858.8 million for the same period in 2015. See " – Factors Affecting Results – Rates and Regulation" for a description of our rates to our Members.

Non-member electric sales increased 240,738 MWhs, or 13.6 percent, to 2,009,837 MWhs for the nine months ended September 30, 2016 compared to 1,769,099 MWhs for the same period in 2015. Non-member electric sales revenue decreased $2.9 million to $92.3 million for the nine months ended September 30, 2016 compared to $95.2 million for the same period in 2015 despite the increase in MWhs. The decrease in non-member electric sales revenue was due to lower non-member long-term firm sales of 36,634 MWhs with revenue of $3.9 million (primarily due to the expiration of several higher priced long-term power sales arrangements partially offset by a new power sales arrangement beginning June 2016), partially offset by higher non-member short-term sales of 277,372 MWhs with revenue of $929,000.

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 $3.6 million to $64.7 million for the nine months ended September 30, 2016 compared to $68.3 million for the same period in 2015. The decrease in other operating revenue was primarily due to an $8.2 million decrease in lease revenue due to the expiration of power sales arrangements at our Knutson and Limon Generating Stations and a $2.5 million decrease in coal sales to other joint owners in the Yampa Project. These decreases in other operating revenue were partially offset by a $5.9 million increase in transmission revenue resulting from our membership in the Southwest Power Pool.

Operating Expenses

Purchased power increased 511,463 MWhs, or 9.7 percent, to 5,780,197 MWhs for the nine months ended September 30, 2016 compared to 5,268,734 MWhs for the same period in 2015. Purchased power expense increased $19.6 million, or 8.3 percent, to $255.0 million for the nine months ended September 30, 2016 compared to $235.4 million for the same period in 2015 due to the increase in MWhs purchased partially offset by a 1.4 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 $18.0 million, or 11.1 percent, to $180.4 million for the nine months ended September 30, 2016 compared to $162.4 million for the same period in 2015. The increase in expense was primarily due to lower coal expense in the second quarter of 2015 resulting from the one-time recognition of $24.4 million as a reduction to fuel expense because of the BNSF rate settlement. Excluding the effect of the BNSF rate settlement, fuel expense decreased $6.4 million to $180.4 million for the nine months ended September 30, 2016 compared to $186.8 million for the same period in 2015. The decrease was primarily due to lower generation for the nine months ended September 30, 2016 compared to the same period in 2015.

Production expense decreased $19.7 million, or 11.0 percent, to $159.7 million for the nine months ended September 30, 2016 compared to $179.4 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 Generating Station).

Depreciation, amortization and depletion expense increased $16.8 million, or 15.4 percent, to $126.1 million for the nine months ended September 30, 2016 compared to $109.3 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 of 2015) at the San Juan Generating Station Unit 3 due to a shortened life associated with the anticipated December 31, 2017 retirement date of the unit.

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

Assets

Construction work in progress decreased $24.1 million, or 11.1 percent, to $192.2 million as of September 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 $154.1 million offset by capital expenditures of $133.7 million. The largest capital expenditures include the Craig Generation Station Unit 2 nitrogen-oxide and Craig Generating Station Unit 3 environmental upgrade projects and various transmission improvements and system upgrades.

Cash and cash equivalents increased $22.6 million, or 15.7 percent, to $167.2 million as of September 30, 2016 compared to $144.6 million as of December 31, 2015. The increase in cash and cash equivalents was primarily due to an increase in accrued interest related to the timing of interest payments for certain obligations that are due during the fourth quarter of 2016 and receiving $37.0 million of net cash related to the withdrawal of KCEC from membership in us (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). Additionally, cash increased $75.0 million due to our commercial paper program and increased $310.0 million due to proceeds from the issuance of debt ($248.0 million from the First Mortgage Bonds, Series 2016A, or Series 2016A Bonds, and $62.0 million from our secured revolving credit facility, or Revolving Credit Agreement). Partially offsetting these increases in cash were debt payments of $416.5 million (principally $333 million on the Revolving Credit Agreement, $37.0 million on the Springerville certificates, $27.1 million on the First Mortgage Obligations, Series 2009C, $7.5 million on CoBank Series 2006B, 2012C, 2014C, unsecured notes, $5.3 million on the City of Gallup Series 2005 pollution control revenue bonds and $4.5 million for the Colowyo Bonds).

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 50.4 percent, to $4.7 million as of September 30, 2016 compared to $9.5 million as of December 31, 2015. The decrease was primarily due to $4.6 million of investment in securities pledged as collateral that was used to pay Colowyo Bonds that matured during the second quarter of 2016.

Deposits and advances increased $9.8 million, or 45.2 percent, to $31.5 million as of September 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 $6.2 million, or 5.0 percent, to $128.7 million as of September 30, 2016 compared to $122.5 million as of December 31, 2015. The increase was primarily due to an increase of $7.5 million related to advance payments to the operating agents of jointly owned facilities and Springerville Generating Station 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 $3.0 million related to preliminary surveys, plans, and investigations (primarily for the Holcomb project).

Equity and Liabilities

Patronage capital equity increased $25.3 million to $977.4 million as of September 30, 2016 compared to $952.1 million as of December 31, 2015. The increase was primarily due to a margin attributable to us of $37.8 million for the nine months ended September 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 $128.8 million, or 3.9 percent, to $3.145 billion as of September 30, 2016 compared to $3.274 billion as of December 31, 2015 and current maturities of long-term debt increased $18.9 million, or 20.6 percent, to $110.3 million as of September 30, 2016 compared to $91.4 million as of December 31, 2015. The total decrease of $109.9 million was primarily due to debt payments of $416.5 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, $7.5 million on CoBank Series 2006B, 2012C, 2014C, unsecured notes, $5.3 million on the City of Gallup Series 2005 pollution control revenue bonds 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 $3.0 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.

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 $75.0 million as of September 30, 2016 compared to $0 as of December 31, 2015. The increase was due to $474.8 million of net proceeds from issuances of commercial paper partially offset by $399.8 million of commercial paper payments (maturities).

Regulatory liabilities increased $47.6 million, or 105.7 percent, to $92.6 million as of September 30, 2016 compared to $45.0 million as of December 31, 2015. The increase was 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 $8.8 million, or 15.8 percent, to $64.0 million as of September 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. Also, on September 1, 2016, we announced an agreement to retire the Nucla Generating Station by December 31, 2022, which is earlier than the previous estimate of December 31, 2049. This resulted in an additional increase in our asset retirement obligation of $2.8 million due to a revision in timing of estimated cash flows.

Other deferred credits increased $13.5 million, or 23.4 percent, to $70.9 million as of September 30, 2016 compared to $57.4 million as of December 31, 2015. The increase was primarily due to the $17.0 million unrealized loss in fair value of the interest rate swaps 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 total $2.3 million as of September 30, 2016. The funds are therefore recorded in other deferred credits. On October 20, 2016, FERC rejected TEP's refund report, including the amount refunded to us, and ordered TEP to recalculate the refund amounts and make time value refunds within 30 days of the date of the order. FERC's order resulted in an additional refund from TEP to us of $13.2 million, which we received on October 24, 2016. These funds will be recorded to other deferred credits due to the uncertainties regarding the ultimate outcome of this matter.

Liquidity

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of debt. As of September 30, 2016, we had $167.2 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2016 is as follows (dollars in thousands):

	Authorized Amount	Available September 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 September 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 September 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 September 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 September 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 $75.0 million of commercial paper outstanding at September 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.

September 30, 2016 compared to September 30, 2015

Operating activities. Net cash provided by operating activities was $226.5 million for the nine months ended September 30, 2016 comprised primarily of net margins of $38.1 million, non-cash depreciation, amortization and depletion of $126.1 million, and other non-cash amortization of $11.0 million. Operating activities were also impacted by an increase in accrued interest related to the timing of interest payments for certain obligations that are due during the fourth 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 $157.4 million for the nine months ended September 30, 2016 comprised primarily of capital expenditures for generation and transmission improvements and system upgrades to serve the growing needs of our Members and to comply with environmental requirements.

Financing activities. Net cash used in financing activities was $46.5 million for the nine months ended September 30, 2016 comprised primarily of long-term debt payments of $416.5 million (principally $333.0 million on our Revolving Credit Agreement, $37.0 million on the Springerville certificates, $27.1 million on the First Mortgage Obligations, Series 2009C, $7.5 million on CoBank Series 2006B, 2012C, 2014C, unsecured notes, $5.3 million on the City of Gallup Series 2005 pollution control revenue bonds and $4.5 million on the Colowyo Bonds) and patronage capital retirements of $15.3 million. The decrease in financing activities was partially offset by debt proceeds of $307.0 million (principally $248.0 million on the Series 2016A Bonds and $62.0 million from our Revolving Credit Agreement) and a net increase of $75.0 million related to our commercial paper ($474.8 million of net proceeds related to issuances of commercial paper partially offset by $399.8 million of commercial paper payments (maturities)).

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.

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 September 30, 2016, we have incurred capital expenditures of approximately $90.3 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 September 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.

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

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 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 September 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 oral arguments took place on September 27, 2016 before ten judges with the Chief Justice recusing himself. 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 generally being maintained at or above investment grade by S&P and Moody’s. We may 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 ends on December 31, 2019. We account for this power purchase agreement as an operating lease since the arrangement is in substance a lease because it conveys to us the right to use power generating equipment for a stated period of time.

Item 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: November 4, 2016

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

Date: November 4, 2016

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