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, 2018

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 No.)
1100 West 116th Avenue **Westminster, Colorado**	**80234**
(Address of principal executive offices)	(Zip Code)

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). **Yes** ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. **Large accelerated filer** ☐ **Accelerated filer** ☐ **Non-accelerated filer** ☒ **Smaller reporting company** ☐ **Emerging growth company** ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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 issuer'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, 2018

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,” “forecast,” “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, 2018	December 31, 2017
ASSETS	(unaudited)	
Property, plant and equipment		
Electric plant		
In service	$ 5,869,636	$ 5,802,844
Construction work in progress	191,965	175,567
Total electric plant	6,061,601	5,978,411
Less allowances for depreciation and amortization	(2,481,954)	(2,409,020)
Net electric plant	3,579,647	3,569,391
Other plant	360,981	283,546
Less allowances for depreciation, amortization and depletion	(110,549)	(105,660)
Net other plant	250,432	177,886
Total property, plant and equipment	3,830,079	3,747,277
Other assets and investments		
Investments in other associations	144,858	143,608
Investments in and advances to coal mines	18,963	18,274
Restricted cash and investments	5,925	5,979
Intangible assets, net of accumulated amortization	5,493	10,986
Other noncurrent assets	9,715	9,604
Total other assets and investments	184,954	188,451
Current assets		
Cash and cash equivalents	119,619	143,694
Restricted cash and investments	134	1,292
Deposits and advances	38,001	27,881
Accounts receivable—Members	105,802	102,035
Other accounts receivable	31,473	16,034
Coal inventory	74,842	46,849
Materials and supplies	92,064	89,459
Total current assets	461,935	427,244
Deferred charges		
Regulatory assets	438,207	454,523
Prepayment—NRECA Retirement Security Plan	33,280	37,607
Other	48,200	38,492
Total deferred charges	519,687	530,622
Total assets	**$ 4,996,655**	**$ 4,893,594**
EQUITY AND LIABILITIES		
Capitalization		
Patronage capital equity	$ 1,061,890	$ 1,003,020
Accumulated other comprehensive income (loss)	(428)	(210)
Noncontrolling interest	109,336	111,295
Total equity	1,170,798	1,114,105
Long-term debt	3,086,601	3,120,286
Total capitalization	4,257,399	4,234,391
Current liabilities		
Member advances	11,290	8,447
Accounts payable	102,540	117,510
Short-term borrowings	206,197	144,667
Accrued expenses	28,235	32,484
Current asset retirement obligations	1,144	3,087
Accrued interest	50,549	32,852
Accrued property taxes	27,820	27,137
Current maturities of long-term debt	97,601	78,004
Total current liabilities	525,376	444,188
Deferred credits and other liabilities		
Regulatory liabilities	89,872	81,824
Deferred income tax liability	15,227	17,205
Asset retirement obligations	47,901	53,768
Other	51,700	53,396
Total deferred credits and other liabilities	204,700	206,193
Accumulated postretirement benefit and postemployment obligations	9,180	8,822
Total equity and liabilities	**$ 4,996,655**	**$ 4,893,594**

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,	
	2018	**2017**	**2018**	**2017**
Operating revenues				
Member electric sales	$ 353,487	$ 346,802	$ 942,916	$ 921,476
Non-member electric sales	31,004	25,354	62,925	85,825
Other	13,666	24,355	38,337	66,540
	398,157	396,511	1,044,178	1,073,841
Operating expenses				
Purchased power	106,166	100,547	271,187	259,322
Fuel	67,840	68,337	168,081	187,658
Production	52,558	46,756	165,750	157,405
Transmission	40,291	38,752	122,255	113,038
General and administrative	6,398	7,326	22,923	19,347
Depreciation, amortization and depletion	38,977	43,332	118,620	131,094
Coal mining	637	12,330	637	30,090
Other	3,897	4,185	11,317	12,953
	316,764	321,565	880,770	910,907
Operating margins	**81,393**	**74,946**	**163,408**	**162,934**
Other income (expense)				
Interest	1,323	1,177	3,762	3,397
Capital credits from cooperatives	1,272	1,323	5,472	5,720
Membership withdrawal	—	—	—	5,000
Other, net	1,466	1,118	3,609	2,547
	4,061	3,618	12,843	16,664
Interest expense, net of amounts capitalized	38,377	37,289	115,380	109,937
Income tax benefit	(151)	(259)	(453)	(863)
Net margins including noncontrolling interest	47,228	41,534	61,324	70,524
Net income attributable to noncontrolling interest	(830)	(736)	(2,454)	(1,409)
Net margins attributable to the Association	**$ 46,398**	**$ 40,798**	**$ 58,870**	**$ 69,115**

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,	
	2018	**2017**	**2018**	**2017**
Net margins including noncontrolling interest	$ 47,228	$ 41,534	$ 61,324	$ 70,524
Other comprehensive income (loss):				
Unrealized gain on securities available for sale	—	48	—	94
Reclassification of unrealized gain on securities available for sale included in net income	—	—	(159)	—
Amortization of actuarial gain on postretirement benefit obligation included in net income	(20)	(20)	(59)	(59)
Income tax expense related to components of other comprehensive income (loss)	—	—	—	—
Other comprehensive income (loss)	(20)	28	(218)	35
Comprehensive income including noncontrolling interest	47,208	41,562	61,106	70,559
Net comprehensive income attributable to noncontrolling interest	(830)	(736)	(2,454)	(1,409)
Comprehensive income attributable to the Association	**$ 46,378**	**$ 40,826**	**$ 58,652**	**$ 69,150**

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Patronage capital equity at beginning of period	$ 1,015,492	$ 989,681	$ 1,003,020	$ 961,364
Net margins attributable to the Association	46,398	40,798	58,870	69,115
Patronage capital equity at end of period	**1,061,890**	**1,030,479**	**1,061,890**	**1,030,479**
Accumulated other comprehensive income (loss) at beginning of period	(408)	(279)	(210)	(286)
Unrealized gain on securities available for sale	—	48	—	94
Reclassification adjustment for unrealized gain on securities available for sale included in net income	—	—	(159)	—
Reclassification adjustment for actuarial gain on postretirement benefit obligation included in net income	(20)	(20)	(59)	(59)
Accumulated other comprehensive income (loss) at end of period	**(428)**	**(251)**	**(428)**	**(251)**
Noncontrolling interest at beginning of period	110,061	109,820	111,295	109,147
Net comprehensive income attributable to noncontrolling interest	830	736	2,454	1,409
Equity distribution to noncontrolling interest	(1,555)	—	(4,413)	—
Noncontrolling interest at end of period	**109,336**	**110,556**	**109,336**	**110,556**
Total equity at end of period	**$ 1,170,798**	**$ 1,140,784**	**$ 1,170,798**	**$ 1,140,784**

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,	
	2018	**2017**
Operating activities		
Net margins including noncontrolling interest	$ 61,324	$ 70,524
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and depletion	118,620	131,094
Amortization of intangible asset	5,493	5,493
Amortization of NRECA Retirement Security Plan prepayment	4,029	4,029
Amortization of debt issuance costs	2,210	1,479
Impairment loss - Holcomb expansion	—	93,494
Deferred Holcomb expansion impairment loss	—	(93,494)
Recognition of deferred membership withdrawal income	—	(5,000)
Recognition of deferred revenue	—	(15,000)
Capital credit allocations from cooperatives and income from coal mines over refund distributions	(1,493)	(1,892)
Changes in operating assets and liabilities:		
Accounts receivable	(18,721)	(5,754)
Coal inventory	(27,040)	15,689
Materials and supplies	(1,854)	(177)
Accounts payable and accrued expenses	(8,734)	(7,973)
Accrued interest	17,696	16,494
Accrued property taxes	684	(2,467)
Other deferred credits - TEP transmission settlement	—	(15,521)
Other	(13,791)	(9,258)
Net cash provided by operating activities	**138,423**	**181,760**
Investing activities		
Purchases of plant	(199,261)	(159,656)
Changes in deferred charges	(1,547)	(239)
Proceeds from other investments	64	61
Net cash used in investing activities	**(200,744)**	**(159,834)**
Financing activities		
Changes in Member advances	257	(4,590)
Payments of long-term debt	(73,943)	(103,138)
Proceeds from issuance of debt	60,000	—
Increase in short-term borrowings, net	61,530	55,181
Retirement of patronage capital	(4,852)	(3,023)
Equity distribution to noncontrolling interest	(4,413)	—
Other	(1,545)	(163)
Net cash provided by (used in) financing activities	**37,034**	**(55,733)**
Net decrease in cash, cash equivalents and restricted cash and investments	**(25,287)**	**(33,807)**
Cash, cash equivalents and restricted cash and investments – beginning	**150,965**	**167,890**
Cash, cash equivalents and restricted cash and investments – ending	**$ 125,678**	**$ 134,083**
Supplemental cash flow information:		
Cash paid for interest	$ 102,916	$ 101,965
Cash paid for income taxes	$ —	$ —
Supplemental disclosure of noncash investing and financing activities:		
Change in plant expenditures included in accounts payable	$ 67	$ (3,287)

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

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, 2017 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. Our consolidated financial position as of September 30, 2018, results of operations for the three and nine months ended September 30, 2018 and 2017, and cash flows for the nine months ended September 30, 2018 and 2017 are not necessarily indicative of the results that may be expected for an entire year or any other period.

Basis of Consolidation

Our consolidated financial statements include the accounts of Tri-State Generation and Transmission Association, Inc. ("Tri-State", "we", "our", "us" or "the Association"), our wholly-owned and majority-owned subsidiaries, and certain variable interest entities for which we or our subsidiaries are the primary beneficiaries. See Note 16 – 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 two 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) and the Missouri Basin Power Project ("MBPP") (operated by Basin Electric Power Cooperative ("Basin")). Our ownership in the San Juan Project terminated December 31, 2017. Each participant in these agreements receives a portion of the total output of the generation facilities, which approximates its percentage ownership. Each participant provides its own financing for its share of each facility and accounts for its share of the cost of each facility. The operating agent for each of these projects allocates the fuel and operating expenses to each participant based upon its share of the use of the facility. Therefore, our share of the plant asset cost, interest, depreciation and other operating expenses is included in our consolidated financial statements.

Effective as of July 1, 2018, our ownership share in MBPP increased to 27.13 percent due to our acquisition of Heartland Consumers Power District's 3.0 percent ownership share in MBPP.

Our share in each jointly owned facility is as follows as of September 30, 2018 (dollars in thousands):

	Tri-State Share	Electric Plant in Service	Accumulated Depreciation	Construction Work In Progress
Yampa Project - Craig Generating Station Units 1 and 2	24.00 %	$ 391,924	$ 237,934	$ 4,360
MBPP - Laramie River Station	27.13 %	420,762	297,335	49,863
Total		$ 812,686	$ 535,269	$ 54,223

Reclassifications

Certain reclassifications have been made to our prior year financial statements to conform to the 2018 presentation.

Accounting Pronouncements-Not Yet Adopted

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)* ("Topic 842"). Topic 842 supersedes the lease recognition requirements in Accounting Standards Codification ("ASC") 840, Leases. Under Topic 842, a lessee is required to recognize lease assets (right-of-use assets) and lease liabilities on the balance sheet for most leases and provide enhanced qualitative and quantitative disclosures. The right-of-use asset represents a lessee's right to use (control the use of) the underlying asset for the lease term. The lease liability represents a lessee's obligation 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 Topic 840. For operating leases, the lessee subsequently recognizes straight-line lease expense over the life of the lease, similar to accounting for operating leases under Topic 840. Lessor accounting remains substantially the same as that applied under Topic 840. Topic 842 includes an accounting policy election by class of underlying asset to exclude short-term leases. A short-term lease is defined as a lease that, at commencement date, has a lease term of 12 months or less and does not include an option to purchase the underlying asset that the lessee is reasonably certain to exercise. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. This amendment is required to be applied using a modified retrospective transition method with the option to elect a package of practical expedients which includes not being required to reassess expired or existing contracts that were assessed under Topic 840, the lease classification for any expired or existing leases that were assessed under Topic 840, and accounting for the initial direct costs for any existing leases. We are currently evaluating the impact of Topic 842 on our consolidated financial statements. We have established a lease project working group and have selected a lease software solution. We are identifying and reviewing our leases and performing a completeness assessment of the lease population. We will adopt ASU 2016-02 beginning in the first quarter of 2019, including our election to adopt the package of practical expedients. We anticipate that the adoption of the amendment may have a significant impact on our consolidated statements of financial position as applicable leases will be recognized as right-of-use assets and lease obligations.

In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842)-Land Easement Practical Expedient for Transition to Topic 842*. This amendment permits an entity to elect an optional transition practical expedient to not evaluate, under Topic 842, land easements that exist or that expired before the entity's adoption of Topic 842. Once an entity adopts Topic 842, the new guidance should be applied prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. We will adopt this optional transition practical expedient upon adoption of ASU 2016-02.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842): Targeted Improvements*. This amendment provides entities with an additional (and optional) transition method to adopt Topic 842. Under this new transition method, an entity recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. An entity's reporting for the comparative periods presented in the financial statements in which it adopts Topic 842 will continue to be in accordance with current GAAP (Topic 840, *Leases*). This amendment also provides lessors with a practical expedient, by class of underlying asset, to not separate non-lease components from the associated lease component if certain conditions are met. Both the optional transition method and lessor practical expedient are effective upon the same adoption date of Topic 842. We will adopt the optional transition method upon adoption of ASU 2016-02. We are currently evaluating the impact of the lessor practical expedient on our consolidated financial statements.

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") based on rates approved by our Board in accordance with our rate policy. Regulatory liabilities represent probable future reductions in rates associated with amounts that are expected to be refunded to our Members based on rates approved by our Board in accordance with our rate policy. We recognize regulatory assets as expenses and regulatory liabilities as operating revenue, other income, or a reduction in expense concurrent with their recovery in rates.

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

	September 30, 2018	December 31, 2017
Regulatory assets		
Deferred income tax expense (1)	$ 15,227	$ 17,205
Deferred prepaid lease expense – Craig Unit 3 Lease (2)	—	3,237
Deferred prepaid lease expense – Springerville Unit 3 Lease (3)	86,578	88,296
Goodwill – J.M. Shafer (4)	52,706	54,843
Goodwill – Colowyo Coal (5)	38,486	39,261
Deferred debt prepayment transaction costs (6)	151,716	158,187
Deferred Holcomb expansion impairment loss (7)	93,494	93,494
Total regulatory assets	438,207	454,523
Regulatory liabilities		
Interest rate swap - unrealized gain (8)	12,641	4,311
Interest rate swap - realized gain (9)	4,332	4,614
Deferred revenues (10)	30,327	30,327
Membership withdrawal (11)	42,572	42,572
Total regulatory liabilities	89,872	81,824
Net regulatory asset	$ 348,335	$ 372,699

(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) Represented deferral of the 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 was amortized to depreciation, amortization and depletion expense in the amount of $6.5 million annually through December 31, 2017. The remaining $3.2 million was amortized to depreciation, amortization and depletion expense for the six month period ending June 30, 2018 and recovered from our Members in rates.

(3) Represents deferral of the 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 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-year period ending in 2035 and recovered from our Members in rates.

(7) Represents deferral of the impairment loss related to development costs, including costs for the option to purchase development rights for the expansion of the Holcomb Generating Station. The plan for the recovery from our Members in rates has not been determined by our Board. Once the plan for recovery is determined, the deferred impairment loss will be recognized in other operating expenses.

(8) Represents deferral of an unrealized gain related to the change in fair value of a forward starting interest rate swap that was entered into in 2016 in order to hedge interest rates on anticipated future borrowings. Upon settlement of this interest rate swap, the realized gain or loss will be deferred and subsequently recognized as interest expense when amortized over the term of the associated long-term debt borrowing. See Note 8 – Long-Term Debt.

(9) Represents deferral of a realized gain of $4.6 million related to the October 2017 settlement of a forward starting interest rate swap that was entered into in 2016. This realized gain was deferred as a regulatory liability and is being amortized to interest expense over the 12-year term of the First Mortgage Obligations, Series 2017A.

(10) Represents deferral of the recognition of non-member electric sales revenues. 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.

(11) Represents the deferral of the recognition of other income recorded in connection with the withdrawal of a former Member from membership in us. 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 and other required investments in the organizations. Our investment in a cooperative increases when a cooperative allocates patronage capital credits to us and it decreases when we receive a cash retirement of the allocated capital credits from the cooperative. A cooperative allocates its patronage capital credits to us based upon our patronage (amount of business done) with the cooperative.

Investments in other associations are as follows (dollars in thousands):

	September 30, **2018**	December 31, **2017**
Basin Electric Power Cooperative	$ 101,820	$ 101,820
National Rural Utilities Cooperative Finance Corporation - patronage capital	11,704	11,232
National Rural Utilities Cooperative Finance Corporation - capital term certificates	16,021	16,085
CoBank, ACB	8,671	8,174
Western Fuels Association, Inc.	2,400	2,346
Other	4,242	3,951
Investments in other associations	$ 144,858	$ 143,608

Our investments in other associations are considered equity securities without readily determinable fair values, and as such are measured at cost minus impairment. We have evaluated these investments for indicators of impairment. There were no impairments of these investments recognized during the nine months ended September 30, 2018 or 2017.

NOTE 4 – INVESTMENTS IN AND ADVANCES TO COAL MINES

We have direct ownership and investments in coal mines to support our coal generating resources. We, and certain participants in the Yampa Project, are members of Trapper Mining, which is organized as a cooperative and is the owner and operator of the Trapper Mine near Craig, Colorado. Our investment in Trapper Mining is recorded using the equity method. In addition, we have ownership in Western Fuels Association, Inc. ("WFA"), which is an owner of Western Fuels-Wyoming, Inc. ("WFW"), the owner and operator of the Dry Fork Mine near Gillette, Wyoming. Dry Fork Mine provides coal to MBPP, which is the owner of Laramie River Generating Station. We, through our undivided interest in the jointly owned facility MBPP, advance funds to the Dry Fork Mine.

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

	September 30, **2018**	December 31, **2017**
Investment in Trapper Mine	$ 15,217	$ 14,998
Advances to Dry Fork Mine	3,746	3,276
Investments in and advances to coal mines	$ 18,963	$ 18,274

NOTE 5 – CASH, CASH EQUIVALENTS AND RESTRICTED CASH AND INVESTMENTS

We consider highly liquid investments with an original maturity of three months or less to be cash equivalents. The fair value of cash equivalents approximates their carrying values due to their short-term maturity.

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 are funds that have been 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.

The following table provides a reconciliation of cash, cash equivalents and restricted cash and investments reported within our consolidated statements of financial position that sum to the total of the same such amount shown in our consolidated statements of cash flows (dollars in thousands):

	September 30, **2018**	December 31, **2017**
Cash and cash equivalents	$ 119,619	$ 143,694
Restricted cash and investments - current	134	1,292
Restricted cash and investments - noncurrent	5,925	5,979
Cash, cash equivalents and restricted cash and investments	$ 125,678	$ 150,965

NOTE 6 – CONTRACT ASSETS AND CONTRACT LIABILITIES

Contract Assets

A contract asset represents an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer when that right is conditioned on something other than the passage of time (for example, the entity's future performance). We have no contract assets as of September 30, 2018.

Accounts Receivable

We record accounts receivable for our unconditional rights to consideration arising from our performance under contracts with our Members and other parties. Uncollectible amounts, if any, are identified on a specific basis and charged to expense in the period determined to be uncollectible. See Note 13 – Revenue.

Contract liabilities (unearned revenue)

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration (or the amount is due) from the customer. We have received deposits from others and these deposits are reflected in unearned revenue (included in other deferred credits and other liabilities on our consolidated statements of financial position) before revenue is recognized, resulting in contract liabilities. During the nine months ended September 30, 2018, we recognized $0.6 million of this unearned revenue in other operating revenues on our consolidated statements of operations.

Our contract assets and liabilities consist of the following (dollars in thousands):

	September 30, **2018**		December 31, **2017**	
Accounts receivable - Members	$	105,802	$	102,035
Other accounts receivable - trade:				
Non-member electric sales		8,796		5,493
Coal sales		-		1,446
Other		15,497		6,634
Total other accounts receivable - trade		24,293		13,573
Other accounts receivable - nontrade		7,180		2,461
Total other accounts receivable	$	31,473	$	16,034
Contract liabilities (unearned revenue)	$	8,122	$	7,567

NOTE 7 – 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.

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, and Yampa Project – Craig Generating Station Units 1 and 2. We also make advance payments to the operating agent of Springerville Unit 3.

We have entered into a forward starting interest rate swap to hedge a portion of our future long-term debt interest rate exposure. The unrealized gain on this interest rate swap of $12.6 and $4.3 million as of September 30, 2018 and December 31, 2017, respectively, was deferred in accordance with the accounting requirements related to regulated operations. See Note 2 – Accounting for Rate Regulation.

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

	September 30, **2018**		December 31, **2017**	
Preliminary surveys and investigations	$	20,254	$	19,737
Advances to operating agents of jointly owned facilities		12,620		10,740
Interest rate swap		12,641		4,311
Other		2,685		3,704
Total other deferred charges	$	48,200	$	38,492

NOTE 8 – 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 ("Master Indenture") except for one unsecured note in the aggregate amount of $36.2 million as of September 30, 2018. Substantially all our assets, rents, revenues and margins are pledged as collateral. The Springerville certificates are secured by the assets of Springerville Unit 3. 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 National Rural Utilities Cooperative Finance Corporation, as lead arranger and administrative agent, in the amount of $650 million ("2018 Revolving Credit Agreement") that expires on April 25, 2023. We had no outstanding borrowings as of September 30, 2018. As of September 30, 2018, we had $443.0 million in availability (including $293.0 million under the commercial paper back-up sublimit) under the 2018 Revolving Credit Agreement.

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

	September 30, **2018**	December 31, **2017**
Total debt	$ 3,197,478	$ 3,211,421
Less debt issuance costs	(20,806)	(21,720)
Less debt discounts	(10,196)	(10,360)
Plus debt premiums	17,726	18,949
Total debt adjusted for debt issuance costs, discounts and premiums	3,184,202	3,198,290
Less current maturities	(97,601)	(78,004)
Long-term debt	$ 3,086,601	$ 3,120,286

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 a forward starting interest rate swap to hedge a portion of our future long-term debt interest rate exposure. We anticipate settling the interest rate swap in conjunction with the issuance of future long-term debt.

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

	Notional Amount	**Fixed Rate (Pay)**	**Benchmark Interest Rate (Receive)**	**Effective Date**	**Maturity Date**
Interest rate swap	$ 80,000	2.304 %	30 year - LIBOR	June 2019	June 2049

NOTE 9 – SHORT-TERM BORROWINGS

We have a commercial paper program under which we issue unsecured commercial paper in aggregate amounts not exceeding the commercial paper back-up sublimit under our secured revolving credit facility, which is the lesser of $500 million or the amount available under our secured revolving credit facility. 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, **2018**	December 31, **2017**
Commercial paper outstanding, net of discounts	$ 206,197	$ 144,667
Weighted average interest rate	2.29 %	1.52 %

At September 30, 2018, $293 million of the commercial paper back-up sublimit remained available under the 2018 Revolving Credit Agreement. See Note 8 – Long-Term Debt.

NOTE 10 – 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 and 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. The New Horizon Mine started final reclamation on June 8, 2017.
>
> 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 generating stations.

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

	Nine Months Ended September 30, **2018**
Asset retirement obligations at beginning of period	$ 56,855
Liabilities incurred	1,421
Liabilities settled	(3,837)
Accretion expense	2,863
Change in cash flow estimate	(8,257)
Total asset retirement obligations at end of period	$ 49,045
Less current asset retirement obligations at end of period	(1,144)
Long-term asset retirement obligations at end of period	$ 47,901

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 11 – OTHER DEFERRED CREDITS AND OTHER LIABILITIES

In 2015, we renewed transmission right of way easements on tribal nation lands where certain of our electric transmission lines are located. $32.9 million will be paid by us for these easements from 2018 through the individual easement terms ending between 2036 and 2040. The present values for the remaining easement payments were $21.1 and $21.3 million as of September 30, 2018 and December 31, 2017, respectively, which are recorded as other deferred credits and other liabilities.

A contract liability represents an entity's obligation to transfer goods or services to a customer for which the entity has received consideration (or the amount is due) from the customer. We have received deposits from others and these deposits are reflected in contract liabilities (unearned revenue) until recognized in other operating revenues over the life of the agreement. We have received deposits from various parties and those that may still be required to be returned are a liability and these are reflected in customer deposits.

The following other deferred credits and other liabilities are reflected on our consolidated statements of financial position (dollars in thousands):

	September 30, 2018	December 31, 2017
Transmission easements	$ 21,067	$ 21,337
Contract liabilities (unearned revenue) - noncurrent	7,257	6,673
Customer deposits	2,434	2,898
Other	20,942	22,488
Total other deferred credits and other liabilities	$ 51,700	$ 53,396

NOTE 12 – EMPLOYEE BENEFIT PLANS

Postretirement Benefits Other Than Pensions

We sponsor three medical plans for all non-bargaining unit employees under the age of 65. Two of the plans provide postretirement medical benefits to full-time non-bargaining unit employees and retirees who receive benefits under those plans, who have attained age 55, and who elect to participate. All three of these non-bargaining unit medical plans offer postemployment medical benefits to employees on long-term disability. The plans were unfunded at September 30, 2018, are contributory (with retiree premium contributions equivalent to employee premiums, adjusted annually) and contain other cost-sharing features such as deductibles.

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

	September 30, 2018
Postretirement medical benefit obligation at beginning of period	$ 8,455
Service cost	456
Interest cost	211
Benefit payments (net of contributions by participants)	(309)
Postretirement medical benefit obligation at end of period	$ 8,813
Postemployment medical benefit obligation at end of period	367
Total postretirement and postemployment medical obligations at end of period	$ 9,180

The service cost component of our net periodic benefit cost is included in operating expenses on our consolidated statements of operations. The components of net periodic benefit cost other than the service cost component are included in other income (expense) on our consolidated statements of operations.

In accordance with the accounting standard related to postretirement benefits other than pensions, actuarial gains and losses are not recognized in income but are instead recorded in accumulated other income on our consolidated statements of financial position. If the unrecognized amount is in excess of 10 percent of the projected benefit obligation, amounts are reclassified out of accumulated other comprehensive income and included in net income as the excess is amortized over the average remaining service lives of the active plan participants. Unrecognized actuarial gains and losses have been determined per actuarial studies for the postretirement medical benefit obligation.

The net unrecognized actuarial gains and losses related to the postretirement medical benefit obligations are included in accumulated other comprehensive income as follows (dollars in thousands):

	September 30, 2018
Amounts included in accumulated other comprehensive income at beginning of period	$ (369)
Amortization of prior service credit into other income (expense)	(59)
Amounts included in accumulated other comprehensive income at end of period	$ (428)

NOTE 13 – REVENUE

Revenue from Contracts with Customers

Our revenues are derived primarily from the sale of electric power to our Members pursuant to long-term wholesale electric service contracts. Our contracts with our Members extend through 2050 for 42 Members and 2040 for the remaining Member.

Member electric sales

Revenues from electric power sales to our Members are primarily from our Class A rate schedule. Our Class A rate schedule for electric power sales to our Members consists of two billing components: an energy rate and demand rates. Our Class A rate schedule is variable and is approved by our Board. Energy and demand have the same pattern of transfer to our Members and are both measurements of the electric power provided to our Members. Therefore, the provision of electric power to our Members is one performance obligation. Prior to our Members' requirement for electric power, we do not have a contractual right to consideration as we are not obligated to provide electric power until the Member requires each incremental unit of electric power. We transfer control of the electric power to our Members over time and our Members simultaneously receive and consume the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method, meter readings are taken at the end of each month for billing purposes, energy and demand are determined after the meter readings and Members are invoiced based on the meter reading. Payments from our Members are received in accordance with the wholesale electric service contracts' terms, which is less than 30 days from the invoice date. Member electric sales revenue is recorded as Member electric sales on our consolidated statements of operations and Accounts receivable – Members on our consolidated statements of financial position.

In addition to our Member electric sales, we have non-member electric sales and other operating revenue which consist of several revenue streams. The following revenue is reflected on our consolidated statements of operations for the three and nine months ended September 30, 2018 and 2017 (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Non-member electric sales:	**2018**	**2017**	**2018**	**2017**
Long-term contracts	$ 11,985	$ 14,441	$ 34,457	$ 49,632
Short-term contracts	19,019	10,913	28,468	21,193
Recognition of deferred revenue	—	—	—	15,000
Coal sales	1,075	11,664	1,075	29,194
Other	12,591	12,691	37,262	37,346
Total non-member electric sales and other operating revenue	$ 44,670	$ 49,709	$ 101,262	$ 152,365

Non-member electric sales

Revenues from electric power sales to non-members are primarily from two long-term contracts and short-term market sales. We recognized $15 million of deferred revenue for the six months ended June 30, 2017, as directed by our Board, which has budgetary and rate-setting authority. See Note 2 – Accounting for Rate Regulation.

We have both long-term and short-term non-member electric sales contracts that provide energy. Prior to our customers' demand for energy, we do not have a contractual right to consideration as we are not obligated to provide energy until the customer demands each incremental unit of energy. We transfer control of the energy to our customer over time and our customer simultaneously receives and consumes the benefits of the electric power. Progress toward completion of our performance obligation is measured using the output method. Payments are received in accordance with the contract terms, which is less than 30 days after the invoice is received by the customer.

Coal Sales

Coal sales revenue results from the sale of coal from the Colowyo Mine to third parties. Colowyo Coal had a long term coal sales contract that expired in December 2017. In 2018, Colowyo Coal entered into a long term coal sales contract with deliveries of coal commencing in the third quarter of 2018. We have an obligation to deliver coal and our progress of our completion toward our performance obligation is measured using the output method. Our performance obligation is completed as coal is delivered.

Other operating revenue

Other operating revenue consists primarily of the following revenue streams: wheeling, transmission, supplying steam and water, and leasing. Wheeling revenue is received when we charge other energy companies for transmitting electricity over our transmission lines (payments are received in accordance with the contract terms which is within 20 days of the date the invoice was issued). Transmission revenue is from Southwest Power Pool's scheduling of transmission across our transmission assets because of our membership in it (Southwest Power Pool collects the revenue from the customer and pays us for the scheduling, system control, dispatch transmission service, and the annual transmission revenue requirement). Steam and water revenue is derived from supplying steam and water to a paper manufacturer located adjacent to the Escalante Station (payments from the customer are received in accordance with the contract terms which is less than 15 days from the invoice date). Each of these services or goods are provided over time and progress toward completion of our performance obligations are measured using the output method. The lease revenue is primarily from a certain power sales arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease because it conveys the right to use power generating equipment for a stated period of time.

NOTE 14 – 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. However, in accordance with our regulatory accounting treatment, 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. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current provision. Our consolidated statements of operations included an income tax benefit of $0.2 million for the three months ended September 30, 2018 and $0.3 million for the comparable period in 2017. Our consolidated statements of operations included an income tax benefit of $0.5 million for the nine months ended September 30, 2018 and $0.9 million for the comparable period in 2017. These income tax benefits are due to an alternative minimum tax credit refund.

Upon filing of our U.S. Federal income tax return during the third quarter, we determined that no adjustments were necessary to our provisional estimates made as of December 31, 2017 with respect to the remeasurement of our deferred tax assets and liabilities under the Tax Cuts and Jobs Act. Our assessment remains provisional as further guidance may be released by the Internal Revenue Service. We will finalize our assessments no later than the fourth quarter of 2018.

NOTE 15 – 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 measured at fair value on a recurring basis with changes in fair value recognized in earnings. 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 cost and fair values of our marketable securities are as follows (dollars in thousands):

	As of September 30, 2018		As of December 31, 2017	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
Marketable securities	$ 673	$ 789	$ 1,007	$ 1,166

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 $115.5 million as of September 30, 2018 and $109.4 million as of December 31, 2017.

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, 2018		As of December 31, 2017	
	Principal Amount	Estimated Fair Value	Principal Amount	Estimated Fair Value
Total debt	$ 3,197,478	$ 3,351,442	$ 3,211,421	$ 3,600,650

Interest Rate Swaps

We entered into a forward starting interest rate swap in 2016 to hedge a portion of our future long-term debt interest rate expense. See Note 8 – Long-Term Debt. This interest rate swap is a derivative instrument in accordance with ASC 815, Derivatives and Hedging, and is recorded at fair value on a recurring basis. The estimated fair value of this interest rate swap utilizes observable inputs based on market data obtained from independent sources and is therefore considered a Level 2 input (quoted prices for similar assets, liabilities (adjusted) and market corroborated inputs) and is included in other deferred charges on our consolidated statements of financial position. At September 30, 2018, the fair value of the interest rate swap was an unrealized gain of $12.6 million, which was deferred in accordance with our regulatory accounting.

NOTE 16 – 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”). The Owner Lessor is the owner of the Springerville Unit 3. We, as general partner of the Springerville Partnership, 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 $799.1 million and $812.7 million at September 30, 2018 and December 31, 2017, respectively, the long-term debt of $416.4 million (including debt premiums) and $431.3 million (including debt premiums) at September 30, 2018 and December 31, 2017, respectively, accrued interest associated with the long-term debt of $4.8 million and $12.4 million at September 30, 2018 and December 31, 2017, respectively, and the 49 percent noncontrolling equity interest in the Springerville Partnership of $109.3 million and $111.3 million at September 30, 2018 and December 31, 2017, respectively.

Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $4.5 million for the three months ended September 30, 2018 and for the comparable period in 2017. Our consolidated statements of operations also include interest expense of $6.9 million for the three months ended September 30, 2018 and $7.1 million for the comparable period in 2017. Our consolidated statements of operations include the Springerville Partnership's depreciation and amortization expense of $13.6 million for the nine months ended September 30, 2018 and $15.1 million for the comparable period in 2017. Our consolidated statements of operations also include interest expense of $20.7 million for the nine months ended September 30, 2018 and $21.3 million for the comparable period in 2017. The net income or loss attributable to the 49 percent noncontrolling equity interest in the Springerville Partnership is 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. 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 is not 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 $2.4 million and $2.3 million at September 30, 2018 and December 31, 2017, respectively, and is included in investments in other associations.

Western Fuels – Wyoming ("WFW"): WFW, the owner and operator of the Dry Fork Mine in Gillette, WY, was organized for the purpose of acquiring and supplying coal, through long-term coal supply agreements, to be used in the production of electric energy at the Laramie River Station (owned by the participants of MBPP) and at the Dry Fork Station (owned by Basin). WFA owns 100 percent of the class AA shares and 75 percent of the class BB shares of WFW, while the participants of MBPP (of which we have a 27.13 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 is not 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 is not 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 $15.2 million at September 30, 2018 and $15.0 million at December 31, 2017.

NOTE 17 – LEGAL

Other than as disclosed below, 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.

In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five weeks in northern New Mexico. Six plaintiff groups, composed of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, Jemez Mountains Electric Cooperative, Inc. ("JMEC") in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs alleged that the fire ignited when a tree growing outside JMEC's right-of-way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. After JMEC settled with one plaintiff group, the remaining cases were Elizabeth Ora Cox, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Norman Armijo, et al., v. Jemez Mountains Electric Cooperative, Inc., et al.; Esequiel Espinoza, et al. v. Allstate Property & Casualty, et al.; Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et al.; and Pueblo de Cochiti., et al. v. Jemez Mountains Electric Cooperative, Inc., et al. The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right-of-way for JMEC's distribution line and that we were also jointly liable for any negligence by JMEC under joint venture and joint enterprise theories. A jury trial commenced on September 28, 2015 on the liability aspect of this matter. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. On September 12 and 25, 2017, we filed notices to appeal to the New Mexico Court of Appeals the determination of our liability for this matter. The plaintiffs filed cross-appeals on their joint venture and joint enterprise claims. In June and July 2018, we reached separate confidential settlements with all plaintiff groups, which amounts were covered by our liability insurance. The district court and the New Mexico Court of Appeals have dismissed all cases related to this matter.

Pursuant to a 30 year power sales contract with another utility that expires in 2020, we currently sell such utility 25 MWs of capacity and energy. The purchase rate for capacity is determined using our Class A wholesale rate schedule. The utility has recently reviewed our charges for capacity since 2000 and alleges such charges are not in accordance with the terms of the power sales contract. We are in discussions with the utility regarding their review of our charges for capacity and no formal dispute resolution process has commenced. It is not possible to predict whether we will incur any liability or to reasonably estimate the amount or range of loss, if any, we might incur in connection with this matter.

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 43 member distribution systems, or Members, that serve large portions of Colorado, Nebraska, New Mexico and Wyoming. We also sell a portion of our generated electric power to other utilities in our regions pursuant to long-term contracts and short-term sale arrangements. Our Members provide retail electric service to suburban and rural residences, farms and ranches, cities, towns and communities, as well as large and small businesses and industries. As of September 30, 2018, our Members served approximately 615,000 retail electric meters over a 200,000 square-mile area. We sold 5.2 million megawatt hours, or MWhs, for the three months ended September 30, 2018, of which 87.9 percent was to Members. Total revenue from electric sales was $384.5 million for the three months ended September 30, 2018, of which 91.9 percent was from Member sales. We sold 13.7 million MWhs for the nine months ended September 30, 2018, of which 90.8 percent was to Members. Total revenue from electric sales was $1.0 billion for the nine months ended September 30, 2018, of which 93.7 percent was from Member sales.

We supply and transmit our Members' electric power requirements through a portfolio of resources, including generating and transmission facilities, long-term purchase contracts and short-term 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 20, 2018, we closed on the purchase of an additional interest in the Missouri Basin Power Project, or MBPP, from Heartland Consumers Power District, or Heartland. MBPP is an integrated power project that includes high voltage transmission lines and 1,710 megawatts of generation at Laramie River Station, located near Wheatland, Wyoming. Effective as of July 1, 2018, the purchase represents an additional 3.0 percent undivided ownership interest in MBPP, which includes transmission rights and approximately 51.3 megawatts of generation. This purchase increases our interest in MBPP to 27.13 percent. The additional transmission included with this purchase will help address congestion issues we face serving our Members in Colorado and postpones the need to build additional transmission. While the additional generation will not significantly change our energy mix, the purchase may delay the need for additional capacity in the future.

During the October 2018 meeting of the Board of Directors, or Board, the final results of a Member assessment completed by a third party during the third quarter was presented. Participants in the assessment included our directors, the general managers of our Members, and the boards of directors of our Members. The results of the assessment showed we enjoy a positive relationship with our Members, but identified areas where we can improve to ensure value and the ability to meet our Members' needs. There is high satisfaction with achievements on 2018 Board priorities, especially progress made on rate stabilization efforts and financial strength.

Our Bylaws and Wholesale Electric Service Contracts

Pursuant to our Bylaws, unless otherwise specified in a written agreement, each Member is required to purchase from us all electric power and energy used by such Member. This requirement in our Bylaws is further specified in a wholesale electric service contract with each Member. Our wholesale electric service contracts with our Members extending through 2050 for 42 Members (which constitute approximately 97.0 percent of our revenue from Member sales for the nine months ended September 30, 2018) and extending through 2040 for the remaining Member (Delta-Montrose Electric Association) are substantially similar. These contracts are subject to automatic extension thereafter until either party provides at least a two years' 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, 2018, 22 Members have enrolled in this program with capacity totaling approximately 143 megawatts of which 105 megawatts are in operation.

Our Members do not have a unilateral right to exit their membership in us. Pursuant to our Bylaws, a Member may only withdraw from membership in us upon compliance with such equitable terms and conditions as our Board may prescribe; provided, however, that no Member shall be permitted to withdraw until it has met all its contractual obligations to us, including all obligations under its wholesale electric service contract with us. From time to time, a Member may request equitable terms and conditions as our Board may prescribe for withdrawal or we may provide for informational purposes all or a portion of our Members equitable terms and conditions for withdrawal. In addition, from time to time, we may be in discussions with a Member regarding the equitable terms and conditions for withdrawal and their request to withdrawal, including granting a Member permission to explore options for potential alternative supplies of power. However, any such permission is not considered authorization to withdrawal and does not change the Member's requirements and obligation to comply with such equitable terms and conditions as our Board may prescribe.

Critical Accounting Policies

As of September 30, 2018, there were no material changes in our critical accounting policies as disclosed in our annual report on Form 10-K for the year ended December 31, 2017.

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 consolidated statements of operations. Net margins are treated as advances of capital by our Members and are allocated to our Members on the basis of revenue from electricity purchases from us. Net losses, should they occur, are not allocated to our Members but are offset by future margins.

Our Board Policy for Financial Goals and Capital Credits, approved and subject to change by our Board, sets guidelines to achieve margins and retain patronage capital sufficient to maintain a sound financial position and to allow for the orderly retirement of capital credits allocated to our Members. Pursuant to the policy, we target rates payable by our Members to produce financial results in excess of the requirements under our indenture, dated effective as of December 15, 1999, or Master Indenture, between us and Wells Fargo Bank, National Association, as trustee. On a periodic basis, our Board will determine whether to retire any patronage capital, and in what amounts, to our Members. As of September 30, 2018, patronage capital equity was $1.062 billion. To date, we have retired approximately $355.5 million of patronage capital to our Members.

Rates and Regulation

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. Revenues from electric power sales to our Members are primarily from our Class A wholesale rate schedule. In 2017 and 2018, our Class A rate schedule (A-40) for electric power sales to our Members consists of two billing components: an energy rate and demand rates. Member rates for energy and demand are set by our Board, consistent with adequate electrical reliability and sound fiscal policy. The energy rate is billed based upon a price per kilowatt hour of physical electricity delivered to our Members without incorporating an on-peak and off-peak period. The two demand rates (a generation demand and a transmission/delivery demand) are 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.

As approved by our Board in September 2018, the A-40 rate schedule will continue in effect for 2019. The average budgeted Member cents/kWh for 2019 will remain the same as 2018.

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 rate schedules to the New Mexico Public Regulation Commission, or NMPRC. The NMPRC only has regulatory authority over rates in New Mexico 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.

No New Mexico Member filed a protest with the NMPRC for the A-40 rate schedule and thus this rate schedule was effective without NMPRC review or approval. Because our A-40 rate schedule will continue in effect for 2019, no filing of our Class A wholesale rate schedule for 2019 with the NMPRC was required.

Master Indenture

As of September 30, 2018, we had approximately $2.8 billion of secured indebtedness outstanding under our Master Indenture. Substantially all of our tangible assets and certain of our intangible assets are pledged as collateral under our Master Indenture. Our Master Indenture requires us to establish rates annually that are reasonably expected to achieve a 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 historical and pro forma basis. Our Master Indenture also requires us to maintain an Equity to Capitalization Ratio (as defined in the Master Indenture) of at least 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. However, in accordance with our regulatory accounting treatment, 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. Under this regulatory accounting approach, the income tax expense (benefit) on our consolidated statements of operations includes only the current portion.

Results of Operations

General

Our electric sales revenues are derived from electric power sales to our Members and non-member purchasers. 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. Short-term 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 our 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, 2018 compared to three months ended September 30, 2017

Operating Revenues

Non-member electric sales increased 64,500 MWhs, or 22.8 percent, to 632,534 MWhs for the three months ended September 30, 2018 compared to 568,034 MWhs for the same period in 2017. Non-member sales revenue increased $5.6 million, or 22.3 percent, to $31.0 million for the three months ended September 30, 2018 compared to $25.4 million for the same period in 2017. The increase in non-member electric sales revenue was due to favorable market conditions, which resulted in increased demand for short-term sales.

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 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. The lease revenue is primarily from a certain power sales arrangement that is required to be accounted for as an operating lease since the arrangement is in substance a lease since it conveys the right to use power generation equipment for a period of time. Coal sales revenue results from the sale of a portion of the coal from the Colowyo Mine to others. Other operating revenue decreased $10.7 million, or 43.9 percent, to $13.7 million for the three months ended September 30, 2018 compared to $24.4 million for the same period in 2017. The decrease in other operating revenue was primarily due to a contract that ended in December 2017 to sell coal from the Colowyo Mine to the other joint owners of the Yampa Project.

Operating Expenses

Purchased power increased 76,600 MWhs, or 3.8 percent, to 2,076,773 MWhs for the three months ended September 30, 2018 compared to 2,000,173 MWhs for the same period in 2017. Purchased power expense increased $5.7 million, or 5.6 percent, to $106.2 million for the three months ended September 30, 2018 compared to $100.5 million for the same period in 2017. The increase in MWhs purchased was primarily due to an increase of 102,556 MWhs of wind and solar energy purchases, offset by decreased short-term market purchased power. Additionally, the average cost per MWh for short-term market and long-term firm purchases was higher for the three months ended September 30, 2018 compared to the same period in 2017.

Production expense increased $5.8 million, or 12.4 percent, to $52.6 million for the three months ended September 30, 2018 compared to $46.8 million for the same period in 2017. The increase in production expense was primarily due to outages at certain of our generating stations during the three months ended September 30, 2018.

Coal mining expense is the Colowyo Mine operating expenses related to the portion of the coal from the Colowyo Mine that is being sold to others. Coal mining expense decreased $11.7 million, or 94.8 percent, to $0.6 million for the three months ended September 30, 2018 compared to $12.3 million for the same period in 2017. The decrease in coal mining expense was due to a contract that ended in December 2017 to sell coal from the Colowyo Mine to the other joint owners in the Yampa Project.

Nine months ended September 30, 2018 compared to nine months ended September 30, 2017

Operating Revenues

Non-member electric sales decreased 276,745 MWhs, or 18.0 percent, to 1,259,347 MWhs for the nine months ended September 30, 2018 compared to 1,536,092 MWhs for the same period in 2017. Non-member electric sales revenue decreased $22.9 million, or 26.7 percent, to $62.9 million for the nine months ended September 30, 2018 compared to $85.8 million for the same period in 2017. The decrease in MWhs sold and non-member electric sales revenue was primarily due to the expiration of long-term power sales arrangements in March and December 2017. The decrease in non-member electric sales revenue was also due to the income recognition of $15.0 million of previously deferred non-member electric sales revenue for the nine months ended September 30, 2017. The recognition in 2017 was approved by our Board in accordance with its budgetary and rate-setting authority.

Other operating revenue decreased $28.2 million, or 42.4 percent, to $38.3 million for the nine months ended September 30, 2018 compared to $66.5 million for the same period in 2017. The decrease in other operating revenue was primarily due to a contract that ended in December 2017 to sell coal from the Colowyo Mine to the other joint owners in the Yampa Project.

Operating Expenses

Purchased power increased 695,243 MWhs, or 12.6 percent, to 6,192,166 MWhs for the nine months ended September 30, 2018 compared to 5,496,923 MWhs for the same period in 2017. Purchased power expense increased $11.9 million, or 4.6 percent, to $271.2 million for the nine months ended September 30, 2018 compared to $259.3 million for the same period in 2017. The increase in MWhs and purchased power expense was primarily due to higher renewable energy and short-term market purchases during the period. Although MWhs purchased increased 12.6 percent, purchase power expense only increased 4.6 percent due to lower short-term market rates for the nine months ended September 30, 2018 compared to the same period in 2017.

Fuel expense includes coal, natural gas and other fuel consumed at the generating stations. Fuel expense decreased $19.6 million, or 10.4 percent, to $168.1 million for the nine months ended September 30, 2018 compared to $187.7 million for the same period in 2017. The decrease in expense was primarily due to lower coal costs and decreased generation at the Craig Generating Station Unit 3 and Springerville Generating Station Unit 3 as a result of unplanned outages. In addition, Nucla Generating Station has had limited generation due to planned outages during 2018 resulting in lower coal costs.

Production expense increased $8.4 million, or 5.3 percent, to $165.8 million for the nine months ended September 30, 2018 compared to $157.4 million for the same period in 2017. The increase in production expense was primarily due to outages at certain of our generating stations during the nine months ended September 30, 2018.

Transmission expense increased $9.3 million, or 8.2 percent, to $122.3 million for the nine months ended September 30, 2018 compared to $113.0 million for the same period in 2017. The increase was primarily due to the recognition of a $7.75 million reduction in transmission expense during the first quarter of 2017 related to the Tucson Electric Power Company transmission services agreement.

Depreciation, amortization, and depletion decreased $12.5 million, or 9.52 percent, to $118.6 million for the nine months ended September 30, 2018 compared to $131.1 million for the same period in 2017. The decrease was primarily due to accelerated depreciation at the San Juan Generating Station and New Horizon Mine in 2017. Depreciation, amortization and depletion expense for the San Juan Generating Station decreased $8.0 million for the nine months ended September 30, 2018 compared to the same period in 2017. The decrease was due to the retirement of the San Juan Generating Station in 2017. New Horizon Mine began final reclamation in June 2017 at which time the mine development and asset retirement costs were fully depreciated. Depreciation expense recognized subsequent to the start of final reclamation is related to equipment in service for final reclamation purposes.

Coal mining expense decreased $29.5 million, or 97.9 percent, to $0.6 million for the nine months ended September 30, 2018 compared to $30.1 million for the same period in 2017. The decrease was due to a coal sales contract that ended in December 2017.

Interest Expense

Interest expense increased $5.5 million, or 5.0 percent, to $115.4 million for the nine months ended September 30, 2018 compared to $109.9 million for the same period in 2017. The increase was due to a reduction in interest capitalized during construction of $2.8 million (primarily due to the cessation of capitalizing development costs for the expansion of the Holcomb Generating Station which is accounted for as a regulatory asset) and higher interest rates on variable rate debt.

Financial condition as of September 30, 2018 compared to December 31, 2017

Assets

Construction work in progress increased $16.4 million, or 9.3 percent, to $192.0 million as of September 30, 2018 compared to $175.6 million as of December 31, 2017. The increase was due to capital expenditures of $98.7 million partially offset by the transfers to electric plant in service for completed projects of $82.3 million. The largest capital expenditures in construction work in progress include a Laramie River Station environmental upgrade project for environmental compliance related to the Regional Haze Rule and various transmission improvements and system upgrades.

Other plant consists of mine assets and non-utility assets (which consist of piping and equipment specifically related to providing steam and water from the Escalante Generating Station to a third party for the use in the production of paper). Other plant increased $77.5 million, or 27.3 percent, to $361.0 million as of September 30, 2018 compared to $283.5 million as of December 31, 2017. The increase was primarily due to capital expenditures for the development of the Collom mining pit at the Colowyo Mine.

Deposits and advances increased $10.1 million, or 36.3 percent, to $38.0 million as of September 30, 2018 compared to $27.9 million as of December 31, 2017. The increase was primarily due to prepayments of annual insurance, memberships and licenses. These prepayments are being amortized to expense over the term of the related insurance, membership or license period.

Coal inventory increased $28.0 million, or 59.8 percent, to $74.8 million as of September 30, 2018 compared to $46.8 million as of December 31, 2017. The increase was primarily due to higher inventory at the Craig Generating Station as a result of an unplanned outage.

Equity and Liabilities

Long-term debt decreased $33.7 million to $3.087 billion as of September 30, 2018 compared to $3.120 billion as of December 31, 2017, and current maturities of long-term debt increased $19.6 million, or 25.1 percent, to $97.6 million as of September 30, 2018 compared to $78.0 million as of December 31, 2017. The net decrease of $14.1 million was primarily due to debt payments of $73.9 million (primarily $49.1 million for the First Mortgage Obligations, Series 2009, $13.7 million for the Springerville certificates, and $11.0 million for various CoBank, ACB and National Rural Utilities Cooperative Finance Corporation debt) partially offset by debt proceeds of $60 million from the First Mortgage Obligations, Series 2017A, Tranche 2 which were issued in April 2018.

Short-term borrowings consist of our commercial paper program that provides an additional financing source for our short-term liquidity needs. Short-term borrowings increased $61.5 million, or 42.5 percent, to $206.2 million as of September 30, 2018 compared to $144.7 million as of December 31, 2017. The increase was due to additional commercial paper issued between January 1, 2018 and September 30, 2018 to fund capital expenditures and working capital requirements.

Accrued interest increased $17.6 million, or 53.9 percent, to $50.5 million as of September 30, 2018 compared to $32.9 million as of December 31, 2017. The increase was due to accruals of $120.6 million for interest payments due in future periods partially offset by cash paid for interest of $103.0 million. Accrued interest as of September 30, 2018 is primarily comprised of the following amounts that are due during the fourth quarter of 2018: $16.1 million for the First Mortgage Obligation Series 2014B, $8.8 million for the First Mortgage Bonds Series 2014E-1 and E-2, $8.8 million for the First Mortgage Bonds Series 2010A, and $3.5 million for the 2016 First Mortgage Bonds Series 2016A. Accrued interest as of September 30, 2018 also includes $4.8 million for the Springerville certificates that are due during the first quarter of 2019.

Liquidity

We finance our operations, working capital needs and capital expenditures from operating revenues and issuance of debt. As of September 30, 2018, we had $119.6 million in cash and cash equivalents. Our committed credit arrangement as of September 30, 2018 is as follows (dollars in thousands):

	Authorized Amount	Available September 30, 2018
2018 Revolving Credit Agreement	$ 650,000 (1)	$ 443,000 (2)

(1) The amount of this facility that can be used to support commercial paper is limited to $500 million.
(2) The portion of this facility that was unavailable at September 30, 2018 was $207 million which was dedicated to support outstanding commercial paper.

The 2018 Revolving Credit Agreement with National Rural Utilities Cooperative Finance Corporation as lead arranger and administrative agent has aggregate commitments of $650 million. The 2018 Revolving Credit Agreement includes a swingline sublimit of $100 million, a letter of credit sublimit of $75 million, and a commercial paper back-up sublimit of $500 million, of which $100 million of the swingline sublimit, $75 million of the letter of credit sublimit, and $293 million of the commercial paper back-up sublimit remained available as of September 30, 2018. As of September 30, 2018, we had $443.0 million of availability under the 2018 Revolving Credit Agreement.

The 2018 Revolving Credit Agreement is secured under the Master Indenture and has a maturity date of April 25, 2023, unless extended as provided therein. Funds advanced under the 2018 Revolving Credit Agreement bear interest either at an adjusted LIBOR rate or an alternate base rate, at our option. The adjusted LIBOR rate is the LIBOR rate for the term of the advance plus a margin (currently 1.00%) based on our credit ratings. The alternate base rate is the highest of (a) the federal funds rate plus ½ of 1.00%, (b) the prime rate, and (c) the one-month LIBOR rate plus 1.00% and plus a margin (currently 0%) based on our credit ratings. We had no outstanding borrowings at September 30, 2018.

The 2018 Revolving Credit Agreement contains customary representations, warranties, covenants, events of default and acceleration, including financial 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, our Board authorized us to issue commercial paper in amounts that do not exceed the commercial paper back-up sublimit under our revolving credit facility, which was $500 million at September 30, 2018, thereby providing 100 percent dedicated support for any commercial paper outstanding. We had $207 million of commercial paper outstanding (prior to netting discounts) at September 30, 2018.

We believe we have sufficient liquidity to fund operations and capital financing needs from projected cash on hand, our commercial paper program, and the 2018 Revolving Credit Agreement.

Cash Flow

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

Nine months ended September 30, 2018 compared to nine months ended September 30, 2017

Operating activities. Net cash provided by operating activities was $138.4 million for the nine months ended September 30, 2018 compared to $181.8 million for the same period in 2017, a decrease of $43.4 million. The decrease in cash provided by operating activities was primarily due to an increase in coal inventory (due to higher inventory at the Craig Generating Station resulting from an unplanned outage) and an increase in purchased power expense (due to higher renewable energy purchases). These decreases in cash were partially offset by an increase in cash collected from Member accounts receivable.

Investing activities. Net cash used in investing activities was $200.7 million for the nine months ended September 30, 2018 compared to $159.8 million for the same period in 2017, an increase of $40.9 million. The increase was primarily due to higher capital expenditures for generation and transmission improvements and system upgrades and the development of the Collom mining pit at the Colowyo Mine.

Financing activities. Net cash provided by financing activities was $37.0 million for the nine months ended September 30, 2018 compared to net cash used in financing activities of $55.7 million for the same period in 2017, an increase in cash provided by financing activities of $92.7 million. The increase was primarily due to debt proceeds of $60.0 million from the First Mortgage Obligations, Series 2017A, Tranche 2 which were issued in April 2018 and lower principal payments of long-term debt for the nine months ended September 30, 2018.

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 depend on a variety of factors, including Member load growth, availability of necessary permits, regulatory changes, environmental requirements, construction delays and costs, and ability to access capital in credit markets. Thus, actual capital expenditures may vary significantly from our projections.

Capital projects include several transmission projects to improve reliability and load-serving capability throughout our service area and development of the Collom mining pit at the Colowyo Mine.

Contractual Commitments

Indebtedness. As of September 30, 2018, we had approximately $2.8 billion of debt outstanding secured on a parity basis under our Master Indenture. As of September 30, 2018, 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 one unsecured note), 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, First Mortgage Bonds, Series 2016A, First Mortgage Obligations, Series 2017A, pollution control revenue bonds, and amounts outstanding, if any, under the 2018 Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Master Indenture. As of September 30, 2018, we have one unsecured note totaling $36.2 million and the Springerville certificates totaling $405.0 million. 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 megawatts, or 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.

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

Coal Purchase Obligations. We have commitments to purchase coal for our generating stations under long-term contracts that expire between 2019 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.

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 and change frequently. The following is a recent development relating to environmental regulations and litigation that may impact us.

Greenhouse Gases. On August 31, 2018, the Environmental Protection Agency, or EPA, published in the Federal Register a proposed rule regarding emission guidelines for greenhouse gas emissions from existing generating units, commonly referred to as the Affordable Clean Energy, or ACE, rule. The ACE proposed rule establishes guidelines for states to follow in developing limitations (i.e., standards of performance) for carbon dioxide emissions from existing units, based on an EPA determination that the best system of emission reduction is heat rate improvement. While the ACE proposed rule establishes that requirements be achievable based on adequately demonstrated technology, implementation of the rule will be at the state level, and it is too early to know how each state in which we operate will administer the rule. If a state implements a very strict interpretation of the rule, it may have a material impact on our operations. We submitted comments to the EPA on the comment period deadline of October 31, 2018.

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, 2017.

Rating Triggers

Our current senior secured ratings are “A3 (stable outlook)” by Moody’s Investors Services, or Moody’s, “A (stable outlook)” by Standard & Poor’s Global Ratings, or S&P, and “A (stable outlook)” by Fitch Rating Inc., or Fitch. Our current short-term ratings are “P-2” by Moody’s, “A-1” by S&P, and “F1” by Fitch.

Our 2018 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 senior secured ratings could result in an increase in each of these pricing components. We do not believe that any such increase would be significant or have a material adverse effect on our financial condition or our future results of operations.

We currently have contracts that require adequate assurance of performance. These include power sales arrangements that are required to be accounted for as operating leases, natural gas supply contracts, coal purchase contracts, and financial risk management contracts. Some of the contracts are directly tied to our credit rating generally being maintained at or above investment grade by S&P and Moody’s. We may enter into additional contracts which may 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 been no 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, 2017.

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

Other than as disclosed below, there have been no material changes from the legal proceedings disclosed in "Item 3 – LEGAL PROCEEDINGS" in our annual report on Form 10-K for the year ended December 31, 2017.

Las Conchas Fire. In June 2011, a wildfire in New Mexico, known as the Las Conchas Fire, burned for five weeks in northern New Mexico. Six plaintiff groups, composed of property owners in the area of the Las Conchas Fire, filed separate lawsuits against our Member, Jemez Mountains Electric Cooperative, Inc., or JMEC, in the Thirteenth District Court, Sandoval County in the State of New Mexico. Plaintiffs alleged that the fire ignited when a tree growing outside JMEC's right of way fell onto a distribution line owned by JMEC as a result of high winds. On January 7, 2014, the district court allowed all parties and related parties to amend their complaints to include the addition of us as a party defendant. After JMEC settled with one plaintiff group, the remaining cases were Elizabeth Ora Cox, et al., v. Jemez Mountains Electric Cooperative, Inc., et al. (second amended complaint filed January 31, 2014); Norman Armijo, et al., v. Jemez Mountains Electric Cooperative, Inc., et al. (amended complaint filed January 16, 2014); Esequiel Espinoza, et al. v. Allstate Property & Casualty, et al. (amended complaint filed April 30, 2014); Jemez Pueblo v. Jemez Mountains Electric Cooperative, Inc., et al. (filed June 10, 2013); and Pueblo de Cochiti., et al. v. Jemez Mountains Electric Cooperative, Inc., et al. (filed June 10, 2013). The allegations in each case were similar. Plaintiffs alleged that we owed them independent duties to inspect and maintain the right of way for JMEC's distribution line and that we were also jointly liable for any negligence by JMEC under joint venture and joint enterprise theories. A jury trial commenced on September 28, 2015 on the liability aspect of this matter. On October 28, 2015, the jury affirmed our position that we and JMEC did not operate as a joint venture or joint enterprise. The jury did find we owed the plaintiffs an independent duty and allocated comparative negligence with JMEC 75 percent negligent, us 20 percent negligent, and the United States Forest Service 5 percent negligent. On September 12 and 25, 2017, we filed notices to appeal to the New Mexico Court of Appeals the determination of our liability for this matter. The plaintiffs filed cross-appeals on their joint venture and joint enterprise claims. In June and July 2018, we reached separate confidential settlements with all plaintiff groups, which amounts were covered by our liability insurance. The district court and the New Mexico Court of Appeals have dismissed all cases related to this matter.

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 9, 2018

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

Date: November 9, 2018

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