Jennifer Prew, utility operator at Laramie River Station.

FINANCIAL STABILITY

Basin Electric's financial success and challenges can often be tied back to two major factors: weather and commodity prices in the energy and agriculture sectors.

From bitter cold in January leading to sales greater than budgeted, to an extended period of hot, dry weather in July leading to significant margins due to increased electricity sales for irrigation and cooling, the utility side of the cooperative had a financially successful year with higher-than-projected margins.

However, the non-utility side of the cooperative, namely subsidiary Dakota Gas, suffered due to lower commodity prices, specifically for the sale of synthetic natural gas and fertilizers.

These challenges faced by Basin Electric are being met by a broad array of solutions, from strategic cost management (see page 9 for more) to the use of a revenue deferral plan.

Two major transactions in 2017 helped Basin Electric secure funding to bolster the cooperative and its projects.

In April 2017, Basin Electric secured $500 million of fixed rate, long-term debt. The financing was used for two primary purposes: to replenish general funds that had been used over the last couple years for the construction of natural gas-based peaking power plants and transmission facilities in western North Dakota, and to finance a portion of the urea production facility at the Great Plains Synfuels Plant.

The launch of this transaction showed very strong interest by investors in Basin Electric. The cooperative received $1.1 billion of subscriptions or offers, which was more than twice the amount ultimately borrowed. The financing has a bullet maturity of 30 years, making it Basin Electric's longest-dated debt.

As of Dec. 31, 2017, Basin Electric had approximately $4.65 billion of total debt outstanding at a weighted average rate of 4.48 percent.

In June 2017, Dakota Gas completed an "amend and extend" of its revolving credit facility. The facility was initially put into place in December 2014. In June, Dakota Gas up-sized the facility from $50 million to $100 million, and extended the maturity of the facility to June 30, 2020. The dollars drawn under this facility are an integral part of the financing for the urea production facility construction project as well.

Even with cost-cutting strategies implemented by Basin Electric, Dakota Gas, and Dakota Coal Company staff, and an increase in member rates in 2016, Basin Electric and its subsidiaries are facing a potentially tough financial forecast, primarily due to low commodity prices.

The Basin Electric family of subsidiaries and facilities is so directly connected through water, fuel, electricity, staff costs, and various commodities, that because of efficiencies and synergies gained on a consolidated basis, Basin Electric is projected to earn relatively strong margins and earnings every year of the forecast period.

The 2018-2027 financial forecast was compiled a little differently than in past years, using a revenue deferral strategy. In the years when the margin is high, revenue is projected to be deferred and cash is

SUBSIDIARY MERGERS

The PrairieWinds subsidiaries were merged into Basin Electric following a resolution approved by the board of directors in its December meeting.

PrairieWinds ND 1, established in 2009, and PrairieWinds SD 1, established in 2010, were merged into Basin Electric in late 2017. Merging the for-profit subsidiaries into Basin Electric had several benefits, including an increase in the consolidated margin.

segregated. The deferred revenue is then projected to be recognized in the rate base in years when it is needed. For example, in the first half of the financial forecast, Basin Electric is setting aside revenue in a deferral, which results in a lower margin. In the last half of the forecast, to hold rates steady, Basin Electric plans to recognize the revenue that was previously deferred.

Using this strategy means Basin Electric is projecting to hold rates flat at the current average member rate of 64.2 mills through 2026. (See page 14 for more on rates.) Over time, the cost of goods and services are projected to continue to rise, plus facility maintenance and other projects that were postponed in the near term will need to be completed later. Thus, a 2.7 mill rate increase is currently being projected in 2027.

For Dakota Gas, commodity prices were forecasted in a different way, implementing a blended approach using forward prices from three different entities to gather the outlook pricing.

Basin Electric's financial forecast team worked with the commodity risk team to determine an alternative case when preparing the financial forecast. Higher margins at Basin Electric compensate for some of the shortfall at Dakota Gas, which is the opposite of what occurred for the cooperative in 2007-2011 when high earnings at Dakota Gas provided support for the low margins at Basin Electric.

Basin Electric holds approximately $7.7 billion in assets and generates approximately $2.2 billion in revenue. Due to the size of the organization, a rate stabilization plan of approximately $75 million, or approximately 3 mills, is prudent.

In conjunction with the rate stabilization plan, Basin Electric and its membership are also reviewing removal of the $200 million limit in deferred revenue allowed under Basin Electric's bylaws. In early 2018, Basin Electric directors approved the addition of up to another $170 million in deferred revenue from 2017 margins to the $23 million deferred in previous years.

Basin Electric's model is built to serve, from operations and governance, to managing finances on behalf of the membership.

The significant drop in commodity prices starting a couple of years ago has posed challenges to Basin Electric, especially for the non-utility operations. Now, more than ever, the cooperative stands on joining together and supporting one another.

2017 FINANCIAL SERVICES ACTIVITIES

ELECTRIC RATES — During 2017, Basin Electric's actual average Class A rate was 64.3 mills per kilowatt-hour, inclusive of a contract extension credit.

SENIOR SECURED BOND RATINGS — Moody's affirmed its A3 rating with a stable outlook, while Fitch Ratings and Standard & Poor's affirmed their A ratings with a negative outlook.

SHORT-TERM RATINGS — Basin Electric's short-term ratings are F1 from Fitch Ratings, A1 from Standard & Poor's Rating Services and P-2 from Moody's Investors Service. Basin Electric uses short-term commercial paper for short-term operating needs and as a source of bridge financing until it can secure long-term financing.

FINANCING — During 2017, Basin Electric issued $500 million in 30-year bonds at a fixed rate of 4.75 percent, increased a $400 million unsecured revolving credit facility to $500 million and extended the term another five years.

LIQUIDITY — At Dec. 31, 2017, cash and cash equivalents, including restricted and designated cash, totaled $366 million. Basin Electric had additional liquidity of $751 million in unused lines of credit, for total available liquidity in excess of $1.1 billion.

OPERATING RESULTS

CONSOLIDATED RESULTS — Basin Electric's financial statements are consolidated with those of its subsidiaries. For the year ending Dec. 31, 2017, the consolidated net margin and earnings was $72.3 million, compared to 2016 consolidated net margin and earnings of $54.6 million.

ELECTRIC — Basin Electric's total utility operating revenue for 2017 was $1.6 billion, a slight increase from 2016. Revenue from member systems totaled $1.6 billion in 2017, an increase of $172.8 million from 2016. Revenue from non-member sales totaled $172.2 million, however, the board of directors approved deferring

PATRONAGE DISTRIBUTION

$250 MILLION

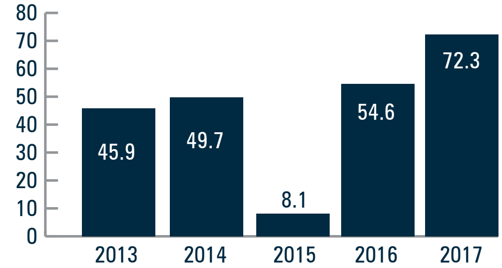
At the end of 2017, Basin Electric distributed $25 million of its previously allocated patronage capital.

The distribution includes the retirement of the remaining $20.54 million of patronage capital allocated for the year 2000, and $4.46 million of patronage capital allocated for 2001.

This distribution brings the total patronage capital returned to member patrons to almost $250 million.

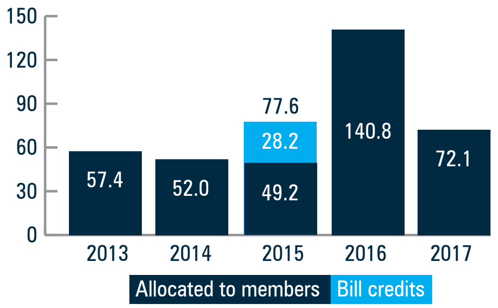
CONSOLIDATED NET MARGINS & EARNINGS

In millions of dollars – for the years ended



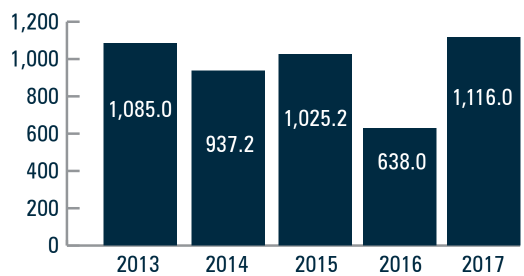
MARGIN DISPOSITION

In millions of dollars – for the years ended



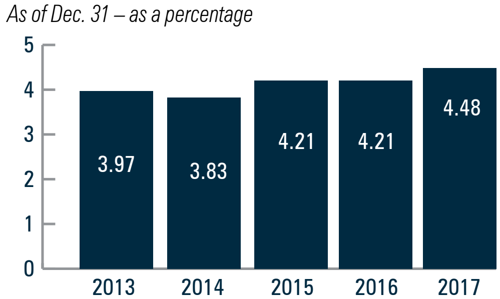
CONSOLIDATED LIQUIDITY

In millions of dollars – at year end



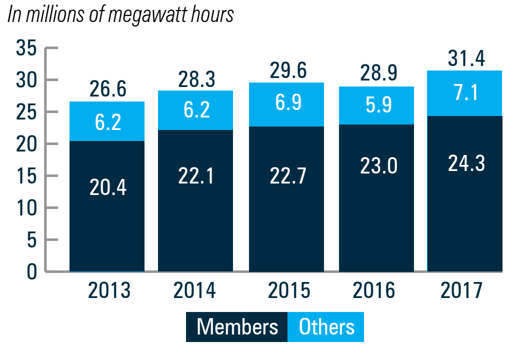
AVERAGE INTEREST RATE ON UTILITY DEBT

As of Dec. 31 – as a percentage



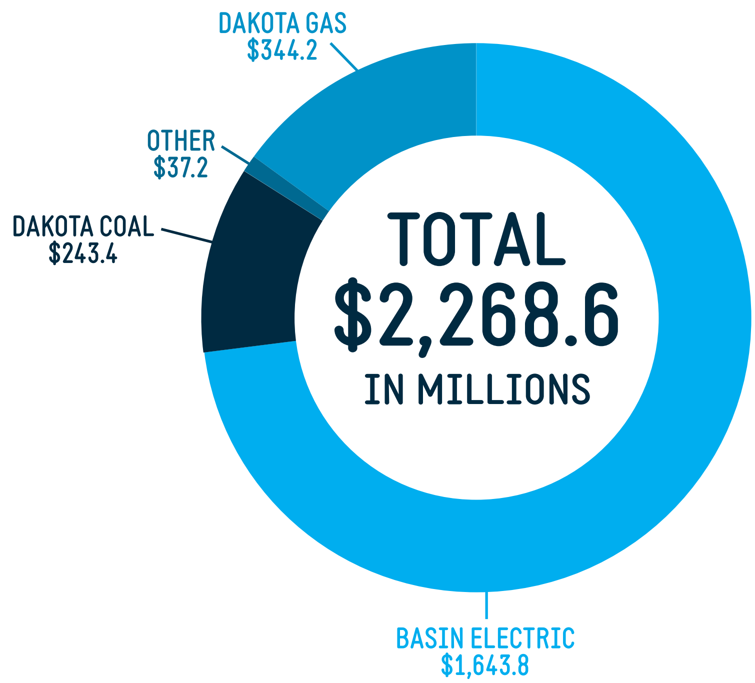
TOTAL ELECTRIC SALES TO MEMBER SYSTEMS & OTHERS

In millions of megawatt hours



CONSOLIDATED GROSS REVENUE

Before intercompany eliminations
For the year ended December 31, 2017



$170 million of surplus sales for recognition in future years. The $172.2 million represents an increase of $33.2 million from 2016. Total utility operating expenses plus interest and other charges before income taxes for 2017 were $1.6 billion, which is $112 million more than in 2016. Basin Electric's utility margin before income taxes, combined with Basin Cooperative Services' net operating results, yielded a combined margin of $72.1 million to be allocated to members.

TAX REFORM — On Dec. 22, 2017, U.S. tax reform legislation was enacted that reduced the U.S. corporate tax rate to 21 percent, requiring Basin Electric and its subsidiaries to re-measure their deferred tax assets and liabilities. The effect of the rate change, recorded in 2017, provided a consolidated tax benefit of $23.2 million to Basin Electric and its subsidiaries.

SUBSIDIARY EARNINGS — Dakota Gas had a net loss of $87.2 million during 2017, and Dakota Coal had net income of $12.8 million.

FINANCIAL POSITION

ASSETS — The total assets of Basin Electric and its subsidiaries as of Dec. 31, 2017, were $7.7 billion, an increase of almost $328.1 million from a year earlier.

MEMBER INVESTMENT PROGRAM — Basin Electric's Member Investment Program ended the year with $192.9 million.

The program offers members an additional investment source at a competitive rate of return while providing Basin Electric with an additional source of liquidity.

DEBT — As of Dec. 31, 2017, Basin Electric had approximately $4.65 billion of debt outstanding including Member Investment Program obligations, at a weighted average interest rate of 4.48 percent.

EQUITY POSITION — At year-end 2017, Basin Electric had total equity of $1.4 billion, an increase of $66 million from 2016. At the end of 2017, equity represented 23.5 percent of Basin Electric's total capitalization. As of Dec. 31, 2017, Basin Electric had an equity-to-asset ratio of 18.4 percent.

CAPITAL CREDIT ALLOCATIONS AND RETIREMENTS — In March 2017, Basin Electric allocated $140.8 million to its patrons. Since 1966, Basin Electric has allocated more than $1 billion in capital credits to its members. In December 2017, Basin Electric returned $25 million of previously allocated capital credits to its members. Basin Electric has retired $249.6 million of allocated patronage over the history of the cooperative.

RETURN OF CASH TO MEMBERS — Since 2000, Basin Electric has returned nearly $658.4 million to the membership through patronage capital retirements, bill credits, and power cost adjustments.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

FIVE-YEAR CONSOLIDATED FINANCIAL SUMMARY

for the years ended December 31, (dollars in thousands)

	2017	2016	2015	2014	2013
Utility operations:					
Operating revenue:					
Sales of electricity for resale	$ 1,567,242	$ 1,531,257	$ 1,419,862	$ 1,459,155	$ 1,325,737
Other electric revenue	23,381	30,321	25,755	22,346	12,072
Total utility operating revenue	1,590,623	1,561,578	1,445,617	1,481,501	1,337,809
Operating expenses:					
Operation	1,060,167	1,001,114	948,317	987,388	905,289
Maintenance	165,556	149,357	160,348	163,433	124,436
Depreciation and amortization	135,438	125,287	154,151	148,028	131,421
Taxes other than income	2,798	2,762	2,773	2,959	2,908
Total utility operating expenses	1,363,959	1,278,520	1,265,589	1,301,808	1,164,054
Interest and other charges:					
Interest on long-term debt	190,648	167,192	156,903	155,679	149,669
Other	17,223	14,088	12,716	8,338	8,044
Total interest and other charges	207,871	181,280	169,619	164,017	157,713
Operating margin	18,793	101,778	10,409	15,676	16,042
Nonoperating margin:					
Interest and other income	47,579	35,039	34,894	32,614	34,267
Patronage allocations from other cooperatives	5,262	3,979	4,105	3,777	7,133
Total nonoperating margin	52,841	39,018	38,999	36,391	41,400
Utility margin before income taxes	71,634	140,796	49,408	52,067	57,442
Nonutility loss before income taxes	(107,350)	(153,150)	(57,614)	(1,575)	(16,854)
Provision for (benefit from) income taxes	(108,056)	(66,921)	(16,281)	811	(5,359)
Net margin and earnings	$ 72,340	$ 54,567	$ 8,075	$ 49,681	$ 45,947
Electric sales information:					
Electric energy sales (in thousands of MWh)					
Members	24,337	23,000	22,664	22,074	20,382
Others	7,113	5,899	6,890	6,251	6,171
Total	31,450	28,899	29,554	28,325	26,553

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
Basin Electric Power Cooperative
Bismarck, North Dakota

We have audited the accompanying consolidated financial statements of Basin Electric Power Cooperative (a North Dakota cooperative corporation) and its subsidiaries (the "Cooperative"), which comprise the consolidated balance sheets as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes to the consolidated financial statements.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Cooperative's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Cooperative as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 13, 2018

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

as of December 31, (dollars in thousands)

	2017	2016
Assets		
Electric plant:		
In service	$ 6,888,220	$ 6,055,327
Property held under capital leases	11,236	118,623
Construction work in progress	126,905	419,035
Total electric plant	7,026,361	6,592,985
Less: accumulated provision for depreciation and amortization	(2,414,509)	(2,165,237)
	4,611,852	4,427,748
Nonutility property:		
Property, plant and equipment	1,455,601	1,764,715
Construction work in progress	667,796	518,216
Total nonutility property	2,123,397	2,282,931
Less: accumulated provision for depreciation and depletion	(718,029)	(820,618)
	1,405,368	1,462,313
Other property, investments and deferred charges:		
Mine related assets (Note 5)	154,726	146,471
Investments in associated companies	41,271	42,365
Other investments (Note 2)	134,392	140,429
Special funds	51,368	46,422
Deferred charges (Note 6)	334,270	306,213
	716,027	681,900
Current assets:		
Cash and cash equivalents	142,362	214,708
Restricted and designated cash and investments (Note 2)	223,658	22,830
Short-term investments	-	100
Customer accounts receivable	167,406	163,336
Other receivables	107,118	99,959
Coal stock, materials and supplies (Note 2)	208,108	197,330
Prepayments and other current assets	85,575	69,183
	934,227	767,446
	$ 7,667,474	$ 7,339,407
Capitalization and Liabilities		
Capitalization:		
Equity:		
Memberships	$ 21	$ 21
Patronage capital	884,606	795,648
Retained earnings of subsidiaries	231,253	277,897
Other equity (Note 7)	291,616	289,494
Accumulated other comprehensive income (loss) (Note 7)	2,341	(17,899)
	1,409,837	1,345,161
Noncontrolling interest	2,324	1,027
	1,412,161	1,346,188
Long-term debt, net of current portion (Note 8)	4,578,261	4,133,002
Capital lease obligations, net of current portion (Note 3)	12,579	116,185
	6,003,001	5,595,375
Deferred credits, taxes and other liabilities (Note 11)	619,472	507,867
Commitments and contingencies (Notes 3 and 12)		
Current liabilities:		
Current portion of long-term debt (Note 8)	68,384	50,846
Current portion of capital lease obligations (Note 3)	1,265	3,342
Accounts payable	201,901	204,313
Notes payable – affiliates	191,043	178,197
Notes payable (Note 12)	478,648	679,516
Taxes and other current liabilities	103,760	119,951
	1,045,001	1,236,165
	$ 7,667,474	$ 7,339,407

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

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

for the years ended December 31, (dollars in thousands)

	2017	2016
Utility operations:		
Operating revenue:		
Sales of electricity for resale:		
Members	$ 1,565,050	$ 1,392,252
Others	2,192	139,005
	1,567,242	1,531,257
Other electric revenue	23,381	30,321
	1,590,623	1,561,578
Operating expenses:		
Operation	1,060,167	1,001,114
Maintenance	165,556	149,357
Depreciation and amortization	135,438	125,287
Taxes other than income	2,798	2,762
	1,363,959	1,278,520
Interest and other charges:		
Interest on long-term debt	190,648	167,192
Other	17,223	14,088
	207,871	181,280
Operating margin	18,793	101,778
Nonoperating margin:		
Interest and other income	47,579	35,039
Patronage allocations from other cooperatives	5,262	3,979
	52,841	39,018
Utility margin before income taxes	71,634	140,796
Nonutility operations:		
Operating revenue:		
Synthetic gas	156,505	126,546
Byproducts, coproduct and other	240,203	246,952
Lignite coal	125,047	114,397
	521,755	487,895
Operating expenses (includes $17,719 and $15,217 of net income attributed to noncontrolling interest)	640,970	644,888
Operating loss	(119,215)	(156,993)
Interest and other income	11,865	3,843
Nonutility loss before income taxes	(107,350)	(153,150)
Margin and loss before income taxes	(35,716)	(12,354)
Benefit from income taxes	(108,056)	(66,921)
Net margin and earnings	$ 72,340	$ 54,567

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

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

for the years ended December 31, (dollars in thousands)

	2017	2016
Net margin and earnings	$ 72,340	$ 54,567
Other comprehensive income (loss):		
Adjustment to post employment liability of $5,318, (net of tax of $1,345) and $5,669, (net of tax of $586)	5,318	5,669
Unrealized gain on securities of $6,476, (net of tax of $3,205) and $3,201, (net of tax of $1,517) and reclassification adjustment of $(982), (net of tax of $(639)), and $0 reclassified into earnings	5,494	3,201
Unrealized gain (loss) on cash flow hedges of $3,265, (net of tax of $1,757) and $(11,900), (net of tax of $(6,408)) and reclassification adjustment of $3,259, (net of tax of $1,755) and $(8,316), (net of tax of $(4,179)) reclassified into earnings	6,524	(20,216)
Total other comprehensive income (loss)	17,336	(11,346)
Comprehensive income	$ 89,676	$ 43,221

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

for the years ended December 31, 2017 and 2016 (dollars in thousands)

	Memberships	Patronage Capital	Retained Earnings of Subsidiaries	Other Equity	Accumulated Other Comprehensive Income (Loss) (Note 7)	Non-controlling Interest	Total
Balance, December 31, 2015	$ 21	$ 638,363	$ 374,078	$ 296,031	$ (6,553)	$ 2,192	$ 1,304,132
Comprehensive income (loss)	-	150,748	(96,181)	-	(11,346)	-	43,221
Transfers to other equity	-	6,537	-	(6,537)	-	-	-
Noncontrolling interest in net margin and earnings	-	-	-	-	-	15,217	15,217
Dividends paid to noncontrolling interest	-	-	-	-	-	(16,382)	(16,382)
Balance, December 31, 2016	21	795,648	277,897	289,494	(17,899)	1,027	1,346,188
Comprehensive income (loss)	-	123,692	(51,352)	-	17,336	-	89,676
Transfers to other equity	-	(9,757)	-	9,757	-	-	-
Retirement of patronage capital	-	(25,000)	-	-	-	-	(25,000)
Reclassification of accumulated other comprehensive income due to tax reform	-	23	(2,449)	(478)	2,904	-	-
Merger of PrairieWinds ND and PrairieWinds SD	-	-	7,157	(7,157)	-	-	-
Noncontrolling interest in net margin and earnings	-	-	-	-	-	17,719	17,719
Dividends paid to noncontrolling interest	-	-	-	-	-	(16,422)	(16,422)
Balance, December 31, 2017	$ 21	$ 884,606	$ 231,253	$ 291,616	$ 2,341	$ 2,324	$ 1,412,161

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

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

for the years ended December 31, (dollars in thousands)

	2017	2016
Operating activities:		
Net margin and earnings	$ 72,340	$ 54,567
Adjustments to reconcile net margin and earnings to net cash from operating activities:		
Depreciation and amortization of property, plant and equipment	197,117	185,626
Increase in reserves	3,968	15,585
Other amortization	17,285	36,943
Patronage capital and other	(34,343)	(5,929)
Deferred income taxes	(56,694)	(57,309)
Other, including regulatory revenue deferral	139,288	-
Income attributable to noncontrolling interest	17,719	15,217
Changes in other operating elements:		
Customer accounts receivable	(4,070)	(43,238)
Other receivables	(7,519)	(14,261)
Coal stock, materials and supplies	(7,782)	3,681
Prepayments and other current assets	(20,594)	(39,406)
Accounts payable	4,466	(6,378)
Taxes and other current liabilities	(11,868)	12,591
Net cash provided by operating activities	309,313	157,689
Investing activities:		
Acquisition of electric plant	(137,216)	(303,177)
Acquisition of nonutility property	(296,127)	(362,231)
Proceeds from sales of nonutility property	6,517	-
Purchase of investments	(235,337)	(25,938)
Sale of investments	43,359	320,585
Purchase of other assets	(9,981)	(2,950)
Net cash used in investing activities	(628,785)	(373,711)
Financing activities:		
Loan advances	526,736	187,636
Principal payments of long-term debt	(52,248)	(46,858)
Payment of debt issue costs	(10,370)	(194)
Proceeds of notes payable - affiliates	1,630,239	1,393,996
Payments of notes payable - affiliates	(1,621,415)	(1,386,256)
Proceeds of notes payable	2,061,880	2,968,055
Payments of notes payable	(2,262,748)	(2,833,298)
Payments under capital lease obligations	(8,526)	(7,173)
Dividends paid to noncontrolling interest	(16,422)	(16,382)
Net cash provided by financing activities	247,126	259,526
Net increase (decrease) in cash and cash equivalents	(72,346)	43,504
Cash and cash equivalents, beginning of year	214,708	171,204
Cash and cash equivalents, end of year	$ 142,362	$ 214,708
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 191,071	$ 163,323
Cash refunded for income taxes	$ (9,669)	$ (261)
Non-cash investing and financing activity:		
Acquisition (disposal) of electric plant and nonutility property through short-term financing	$ 35,201	$ (20,175)

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

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

for the years ended December 31, (dollars in thousands)

1. ORGANIZATION

Basin Electric Power Cooperative (Basin Electric) is an electric generation and transmission cooperative corporation, organized and existing under the laws of the State of North Dakota. It serves member electric service needs in a nine-state region of North Dakota, South Dakota, Montana, Wyoming, New Mexico, Colorado, Nebraska, Minnesota and Iowa. Basin Electric's power supply resources are composed of its own generating facilities and contractual power purchase arrangements. It delivers power and energy over its own transmission facilities and through contractual arrangements with other power supply entities in the region, primarily the Western Area Power Administration.

Basin Electric's accounting records are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission. The rates charged to its members for electric service are established by Basin Electric's Board of Directors.

Basin Electric has two wholly owned for-profit subsidiaries, Dakota Gasification Company (Dakota Gas), and Dakota Coal Company (Dakota Coal). Two other wholly owned for-profit subsidiaries, PrairieWinds ND 1, Inc. and PrairieWinds SD 1, Inc., were merged with Basin Electric on December 31, 2017. Basin Electric also has one wholly owned not-for-profit subsidiary, Basin Cooperative Services (BCS). Dakota Gas has a wholly owned for-profit subsidiary, Souris Valley Pipeline Limited (SVPL). Dakota Coal has a wholly owned for-profit subsidiary, Montana Limestone Company (MLC). Dakota Gas owns and operates the Great Plains Synfuels Plant (Synfuels Plant) which converts lignite coal into pipeline-quality synthetic gas and anhydrous ammonia as a coproduct, as well as a number of byproducts including carbon dioxide (CO_2), and is located adjacent to Basin Electric's Antelope Valley Station (AVS) electric generating plant. These plants share certain facilities, and coal and water supplies. Basin Electric also supplies the Synfuels Plant with electric capacity and energy, and Dakota Gas supplies various Basin Electric peaking stations and AVS with synthetic gas. SVPL owns and operates a CO_2 pipeline in Saskatchewan, Canada. Dakota Coal purchases lignite coal from the Freedom Mine, a coal mine in North Dakota that is owned and operated by The Coteau Properties Company (Coteau), a wholly owned subsidiary of The North American Coal Corporation (NACoal). Coteau is a variable interest entity of Dakota Coal. Pursuant to the coal purchase agreement, Dakota Coal is obligated to provide financing for and has certain rights with respect to the operation of the coal mine. The lignite coal is used in Basin Electric's Leland Olds Station (LOS), AVS, and Dakota Gas' Synfuels Plant. Dakota Coal coordinates procurement and rail delivery of Powder River Basin coal to the Laramie River Station (LRS), the Dry Fork Station (DFS) and LOS. Dakota Coal also owns a lime plant that sells lime to AVS, the Missouri Basin Power Project (MBPP) and others. MLC operates a limestone quarry and owns and operates a fine grind plant, both in Montana, and sells limestone to Dakota Coal's lime plant, LOS and others. BCS provides certain nonutility property management services to Basin Electric. Basin Electric is a 42.27 percent owner of the MBPP and acts as the operating agent for the 1,710 megawatt LRS generating plant in Wyoming, associated transmission facilities and the Grayrocks Dam and Reservoir. Basin Electric is a 92.9 percent owner of the DFS generating plant in Wyoming and acts as the operating agent for the 386 megawatt plant.

2. SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION — The consolidated financial statements include the accounts of Basin Electric, its wholly owned subsidiaries and its variable interest entity, Coteau. All intercompany investments, debt, and receivable and payable accounts have been eliminated in consolidation. Charges from BCS, Dakota Gas, Dakota Coal, MLC, Coteau, PrairieWinds ND and PrairieWinds SD to Basin Electric and charges from Basin Electric to BCS, Dakota Gas, Dakota Coal, MLC, Coteau, PrairieWinds ND and PrairieWinds SD are not eliminated as Basin Electric includes the results of these activities in the determination of rates charged to its members (Note 13).

USE OF ESTIMATES — The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting period. Estimates are used for items such as plant depreciable lives, actuarially determined benefit costs, valuation of derivatives, asset retirement obligations, and benefit from income taxes. Ultimate results could differ from those estimates.

CASH AND CASH EQUIVALENTS — Basin Electric considers all investments purchased 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 AND DESIGNATED CASH AND INVESTMENTS — Cash and investments and funds held by a financial institution, as trustee, at December 31 were restricted for the following purposes:

	2017	2016
Cash and investments:		
MBPP operating funds	$ 30,774	$ 22,830
Other investments:		
Funds held in trust for an asset retirement obligation by Bank of Montreal as trustee for SVPL	$ 2,372	$ 2,190

Cash and investments at December 31 were designated by the Basin Electric Board of Directors for the following purposes:

	2017	2016
Cash and investments:		
Deferred revenue	$ 192,884	$ -

INVESTMENTS — Basin Electric classifies its investments as either available-for-sale or held-to-maturity. The cost of securities sold is based on the specific identification method. Available-for-sale securities are included in Short-term investments, Mine related assets and Other investments on the Consolidated Balance Sheets. The cost, unrealized holding gains and losses, and fair value of available-for-sale securities were as follows:

	December 31, 2017				December 31, 2016			
		Gross Unrealized Holding				Gross Unrealized Holding		
	Cost	Gains	Losses	Fair Value	Cost	Gains	Losses	Fair Value
Equity securities	$ 77,602	$ 26,271	$ (1)	$ 103,872	$ 49,482	$ 17,453	$ -	$ 66,935
Guaranteed investment certificates	477	-	-	477	744	-	-	744
Canadian government bonds	-	-	-	-	1,460	-	14	1,446
Corporate commercial paper	-	-	-	-	100	-	-	100
Investment funds	752	-	-	752	-	-	-	-
Preservation funds	250	-	-	250	-	-	-	-
	$ 79,081	$ 26,271	$ (1)	$ 105,351	$ 51,786	$ 17,453	$ 14	$ 69,225

During 2017 and 2016, sales proceeds on securities classified as available-for-sale were $11,062 and $10,960.

The fair value of available-for-sale debt securities by contracted maturity date at December 31, 2017 was as follows:

	2017
Due through one year	$ 1,223
Due after one year through five years	256
Due after five years	-
	$ 1,479

Held-to-maturity securities are included in Cash and cash equivalents and Restricted and designated cash and investments. The cost, unrealized holding gains and losses, and fair value of held-to-maturity securities were as follows:

	December 31, 2017				December 31, 2016			
		Gross Unrealized Holding				Gross Unrealized Holding		
	Cost	Gains	Losses	Fair Value	Cost	Gains	Losses	Fair Value
Money market	$ 250,243	$ -	$ -	$ 250,243	$ 185,027	$ -	$ -	$ 185,027
Corporate commercial paper	91,048	-	-	91,048	33,800	-	-	33,800
	$ 341,291	$ -	$ -	$ 341,291	$ 218,827	$ -	$ -	$ 218,827

All held-to-maturity securities have contracted maturity dates of three months or less.

Investment securities, in general, are exposed to various risks, such as interest rate, credit and overall volatility. Due to such risks, it is reasonably possible that changes in the values of investment securities will occur in the near term and that such changes could materially affect amounts reported in the consolidated financial statements. Management regularly monitors the difference between the cost and fair market values of its investments. If any of Basin Electric's investments experience a decline in value that is believed to be other than temporary, a loss is recognized in Interest and other income in the Consolidated Statements of Operations.

Included in Other investments is the cash surrender value of life insurance policies of $6,310 and $6,781, as of December 31, 2017 and 2016.

COAL STOCK, MATERIALS AND SUPPLIES — Byproducts, coproduct, and limestone inventories are stated at the lower of average cost or net realizable value, and fuel stock, and materials and supplies inventories are stated at average cost, which approximates market. Inventories were as follows at December 31:

	2017	2016
Materials and supplies	$ 148,025	$ 141,371
Coal and fuel oil	37,553	35,954
Byproducts, coproduct and limestone inventory	11,140	11,432
Ammonia	10,677	7,099
Ammonium sulfate	246	942
Process inventory	467	532
	$ 208,108	$ 197,330

PATRONAGE CAPITAL AND RETAINED EARNINGS OF SUBSIDIARIES — At the discretion of Basin Electric's Board of Directors, utility margins are allocated to members on a patronage basis or may be offset in whole or in part against current or prior losses. Certain other margins may also be set aside as other equity for improvements, new construction, depreciation and contingencies as determined by the Board of Directors under the Basin Electric Indenture. Basin Electric may not retire patronage capital if, after the distribution, an event of default would exist or Basin Electric's equity would be less than 20 percent of total long-term debt and equity. Cumulative patronage capital retired at December 31, 2017 was $249,626.

REVENUE RECOGNITION — Revenue from electric energy is recognized when delivered. Synthetic gas revenue is recognized upon delivery or when tendered in accordance with contract requirements. Byproduct and coproduct revenue are generally recognized upon delivery. Coal, lime and limestone revenue are recognized upon delivery.

ELECTRIC PLANT AND NONUTILITY PROPERTY — Electric plant and nonutility property are stated at cost, including contract work, direct labor and materials, allocable overheads and allowance for funds used during construction. Interest charged and capitalized to construction during 2017 and 2016 totaled $33,611 and $38,908. Repairs and maintenance are charged to operations as incurred. When electric plant is retired, sold, or otherwise disposed of, the original cost plus the cost of removal less salvage value is charged to accumulated depreciation and the corresponding gain or loss is amortized over the remaining life of the plant. When nonutility property is retired or sold, the cost and the related accumulated depreciation are eliminated and any gain or loss is reflected in nonutility operations.

DEPRECIATION AND AMORTIZATION — Electric plant is depreciated using the straight-line method based on the estimated useful lives of the various classes of property. The annual depreciation provision as a percent of average depreciable electric plant in service was approximately 1.84 and 1.80 percent in 2017 and 2016. Annual electric plant depreciation expense totaled $135,738 and $120,372 for 2017 and 2016.

Nonutility property is depreciated using a straight-line method over a remaining estimated useful life of 30 years, except for certain byproduct assets which are depreciated over a remaining estimated useful life of 15 years. Annual nonutility depreciation expense totaled $59,350 and $65,254 for 2017 and 2016.

Accelerated and straight-line depreciation methods are used for income tax reporting purposes.

RECOVERABILITY OF LONG-LIVED ASSETS — Basin Electric accounts for the impairment or disposal of long-lived assets in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 360, Property, Plant, and Equipment, which requires long-lived assets, such as property and equipment, to be evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment loss is recognized when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset (if any) are less than the carrying value of the asset. When an impairment loss is recognized, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques. To date, management has determined that no impairment of these assets exists.

REGULATORY ASSETS AND LIABILITIES — Basin Electric is subject to the provisions of ASC 980, Regulated Operations. Regulatory assets represent probable future revenue to Basin Electric associated with certain costs which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are to be credited to customers through the ratemaking process (Notes 6 and 11). Basin Electric has entered into various swaps and option arrangements to limit its exposure to fluctuation in interest rates and natural gas prices. Under ASC 980, changes in fair value of all hedge arrangements, to the extent they are recoverable through future rates, are deferred and recorded in regulatory accounts. Regulatory assets and liabilities were as follows at December 31:

	2017	2016
Regulatory assets included in:		
Deferred charges	$ 329,851	$ 300,972
Mine related assets	21,130	22,593
	350,981	323,565
Regulatory liabilities included in:		
Deferred credits, taxes and other liabilities	(202,024)	(24,888)
Net regulatory assets	$ 148,957	$ 298,677

As of December 31, 2017, Basin Electric's regulatory assets are reflected in rates charged to customers over periods ranging from 3 to 30 years. If all or a separable portion of Basin Electric's operations no longer are subject to the provisions of ASC 980, a write-off of related regulatory assets would be required, unless some form of transition recovery (refund) continues through rates established and collected for Basin Electric's remaining regulated operations. In addition, Basin Electric would be required to determine any impairment to the carrying costs of deregulated plant and inventory assets.

DERIVATIVE FINANCIAL INSTRUMENTS — The Boards of Directors of Basin Electric and its wholly-owned subsidiaries, Dakota Gas and Dakota Coal (said Boards of Directors being collectively referred to herein as the Board), adopted Board Policy 02B Cooperative Commodity Risk Management, dated October 13, 2015 (Policy). The Policy refers to Basin Electric, Dakota Gas, and Dakota Coal collectively as Affiliated Companies. The Policy provides a risk management framework and direction to staff engaged in the purchase, sale, optimization, control, accounting, and settlement of commodity transactions affecting each of the Affiliated Companies. This Commodity Risk Management Manual (Manual) fulfills the requirement of the Policy that the Risk Management Steering Committee (RMSC) adopt a written commodity risk management manual. The RMSC adopted the Manual on August 15, 2016, and amended the Manual on December 5, 2017.

This Manual is designed to establish the commodity risk management and internal control framework under which the Affiliated Companies may engage in commodity transacting and hedging activities. This Manual governs contemplated commodity transactions, as well as, the management, tracking, and reporting of risks related to the commodity transacting portfolio. The Affiliated Companies' commodity transacting program was developed to hedge inherent market risks associated with the business. In offsetting market risk, the Affiliated Companies are exposed to other forms of incremental risk such as credit or liquidity risk.

Dakota Gas entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in natural gas prices. These derivative financial instruments effectively fix the price of synthetic natural gas between $2.80 and $5.90 per dekatherm for a portion of the forecasted sales (1% to 42% on a monthly basis) through March 2020. These derivative financial instruments attempt to provide for sales prices in excess of Dakota Gas's average before tax cost of production and are only to mitigate the risk of natural gas price movements. Any changes in cash flows from the underlying sales are offset by corresponding changes in the cash flows from the derivatives. Dakota Gas and its counterparties have various obligations to post collateral with each other to partially backstop their synthetic gas derivative activity based upon fluctuations in the price of natural gas.

Certain financial instruments valued at $2,013 and $(9,917), at December 31, 2017 and 2016, meet the criteria for hedge accounting under ASC 815, Derivatives and Hedging, and as a result, unrealized gains or losses on the instruments were recognized in Accumulated other comprehensive income (loss) and will subsequently be reclassified to synthetic gas revenue in the Consolidated Statements of Operations when the hedged sales are recorded. Dakota Gas evaluates and quantifies any hedge ineffectiveness on a quarterly basis, and Dakota Gas's natural gas cash flow hedges had no ineffectiveness in 2017 or 2016. Derivative financial instruments valued at $3,737 and ($15,809), at December 31, 2017 and 2016, did not meet the criteria for hedge accounting under ASC 815, and as a result, changes in market value of these instruments were recognized on the Consolidated Statements of Operations as synthetic gas revenue. In the December 31, 2017 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $8,108, was included in Prepayments and other current assets, the current liability portion, ($1,621), was included in Taxes and other current liabilities and the noncurrent liability portion, ($737) was included in Deferred credits, taxes and other liabilities. In the December 31, 2016 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $1,467, was included in Prepayments and other current assets, the current liability portion, ($25,277), was included in Taxes and other current liabilities and the noncurrent liability portion, ($1,916), was included in Deferred credits, taxes and other liabilities.

Dakota Gas also entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in tar oil prices. These derivative financial instruments effectively fix the price of tar oil between $35.00 and $55.25 per barrel for a portion of the forecasted sales (2% to 59% on a monthly basis) through March 2020. These derivative financial instruments attempt to provide for sales prices in excess of Dakota Gas's average before tax cost of production and are held only to mitigate the risk of tar oil price movements.

Certain derivative financial instruments valued at ($10,533) and ($6,523), at December 31, 2017 and 2016, meet the criteria for hedge accounting under ASC 815, and as a result, unrealized gains or losses on the instruments were recognized in Accumulated other comprehensive income (loss) and will subsequently be reclassified to Byproducts, coproduct and other revenue in the Consolidated Statements of Operations when the underlying sales are recorded. Dakota Gas evaluates and quantifies any hedge ineffectiveness on a quarterly basis, and Dakota Gas's tar oil cash flow hedges had no ineffectiveness in 2017 or 2016. Derivative financial instruments valued at ($713) and $72, at December 31, 2017 and 2016, did not meet the criteria for hedge accounting under ASC 815, and as a result, changes in market value of these instruments were recognized on the Consolidated Statements of Operations as Byproducts, coproduct and other revenue. In the December 31, 2017 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $646, was included in Prepayments and other current assets and the noncurrent asset portion, $7, was included in Other investments. The fair value of the current liability portion, ($8,756), was included in Taxes and other current liabilities and the noncurrent liability portion, ($3,143), was included in Deferred credits, taxes and other liabilities. In the December 31, 2016 Consolidated Balance Sheets, the fair value of the current liability portion of these derivative financial instruments, ($4,510), was included in Taxes and other current liabilities and the noncurrent liability portion, ($1,941), was included in Deferred credits, taxes and other liabilities.

Dakota Gas also entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in electricity prices paid at the Synfuels Plant. Derivative financial instruments, valued at ($1,751) and $974, at December 31, 2017 and 2016, did not meet the criteria for hedge accounting under ASC 815, and as a result, all changes in market value on the instruments are recognized in Nonutility operating expense on the Consolidated Statements of Operations. In the December 31, 2017 Consolidated Balance Sheets, the fair value of the current liability portion of these derivative financial instruments, ($184), was included in Taxes and other current liabilities and the noncurrent liability portion, ($1,567), was included in Deferred credits, taxes and other liabilities. In the December 31, 2016 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $644, was included in Prepayments and other current assets and the current liability portion, $330, was included in Taxes and other current liabilities.

In 2017 and 2016, Dakota Gas also entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in diesel prices paid to transport products. Derivative financial instruments, valued at $245 and $440, at December 31, 2017 and 2016, did not meet the criteria for hedge accounting under ASC 815, and as a result, all changes in market value on the instruments are recognized in Nonutility operating expenses on the Consolidated Statements of Operations. In the December 31, 2017 and 2016 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $245 and $326, was included in Prepayments and other current assets and the non-current asset portion for 2016, $114, was included in Other investments.

Beginning in 2017, Dakota Gas entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in naphtha products. Derivative financial instruments, valued at ($641) at December 31, 2017, did not meet the criteria for hedge accounting under ASC 815, and as a result, all changes in market value on the instruments are recognized in the Consolidated Statements of Operations as Byproducts, coproduct and other revenue. In the December 31, 2017 Consolidated Balance Sheets, the fair value of the current liability portion of these derivative financial instruments ($641), was included in Taxes and other current liabilities.

Basin Electric entered into various interest-rate swap agreements to reduce the impact of changes in interest rates on certain of its variable rate long-term bonds. There were four interest rate swaps outstanding at December 31, 2017 that effectively change the interest rate on $100,000 of Basin Electric's variable rate bonds due in 2032 to a fixed rate of 6.18 percent, the interest rate on $50,000 of Basin Electric's variable rate bonds due in 2032 to a fixed rate of 4.95 percent, and the interest rate on $50,000 of Basin Electric's variable rate bonds due in 2030 to a fixed rate of 5.33 percent. In October of 2013, Basin Electric's Board of Directors took action to defer accumulated and future changes in the fair value of these swaps as a regulatory item to be recovered through rates in the future. Only current settlements of these interest rate swaps are included in earnings, which resulted in charges to interest expense for the years ended December 31, 2017 and 2016 of $9,130 and $10,341. The change in fair value for the years ended December 31, 2017 and 2016 resulted in a deferred gain of $2,558 and $9,786. At December 31, 2017 and 2016, the fair value of the obligation related to the interest rate swap agreements of $79,213 and $81,771 were included in Deferred credits, taxes and other liabilities on the Consolidated Balance Sheets. A regulatory deferred asset, which represents the amount to be recovered through future rates, is included in Deferred charges on the Consolidated Balance Sheets (Note 6).

Basin Electric entered into a series of floating-to-fixed swap agreements valued at ($8,220) and ($938) at December 31, 2017 and 2016, for natural gas, power and diesel to manage the variable price risk associated with the forecasted commodity exposure through 2021. In the December 31, 2017 Consolidated Balance Sheets, the fair value of the current portion of the assets related to these derivative financial instruments, $1,670, was included in Prepayments and other current assets. At December 31, 2017, the fair value of the current portion of the liability related to Basin Electric's derivative financial instruments was included in Taxes and other current liabilities ($2,441) and the noncurrent portion of the liability was included in Deferred credits, taxes and other liabilities ($7,449) on the Consolidated Balance Sheets. A regulatory deferred asset, which represents the amount to be recovered through future rates, was included in Deferred charges on the Consolidated Balance Sheets. In the December 31, 2016 Consolidated Balance Sheet, the fair value of the current portion of the assets related to these financial instruments, $3,065, was included in Prepayments and other assets and the noncurrent portion, $390, was included in Other assets. At December 31, 2016, the fair value of the liability related to Basin Electric's natural gas swap agreements was included in Deferred credits, taxes and other liabilities ($3,919) and Taxes and other current liabilities ($474) on the Consolidated Balance Sheets. A regulatory deferred asset, which represents the amount to be recovered through future rates, is included in Deferred charges on the Consolidated Balance Sheets (Note 6).

In 2017 and 2016, Dakota Coal also entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuation in the diesel cost component of the coal costs paid to Coteau. These derivative financial instruments effectively fix the price paid for diesel between $1.63 and $1.99 per gallon for a portion of the forecasted purchases (42% to 67% on a monthly basis) through December 2019. These derivative financial instruments attempt to mitigate the risk of price movement in the diesel cost component of coal costs.

Certain derivative financial instruments valued at $1,793 and $812 at December 31, 2017 and 2016 meet the criteria for hedge accounting under ASC 815, and as a result, unrealized gains or losses on the instruments were recognized in Accumulated other comprehensive income (loss) and will subsequently be reclassified to Operating expenses in the Consolidated Statements of Operations when the underlying purchases are recorded. Dakota Coal evaluates and quantifies any hedge ineffectiveness on a quarterly basis, and Dakota Coal's diesel cash flow hedges had no ineffectiveness in 2017 and 2016. In the December 31, 2017 and 2016 Consolidated Balance Sheets, the fair value of the current asset portion of these derivative financial instruments, $1,253 and $277, were included in Prepayments and other current assets and the noncurrent asset portions, $477 and $535, were included in Other investments.

Basin Electric, Dakota Gas, and Dakota Coal also enter into contracts for the purchase and sale of various commodities for use in their business operations. ASC 815 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from ASC 815 as normal purchases or normal sales. Basin Electric, Dakota Gas, and Dakota Coal evaluate all of their contracts when such contracts are entered into to determine if they are derivatives and, if so, if they meet the normal purchase normal sale exception requirements under ASC 815.

Basin Electric, Dakota Gas, and Dakota Coal are exposed to credit risk loss in the event of nonperformance by the counterparties to their derivative financial instruments. However, Basin Electric, Dakota Gas, and Dakota Coal do not anticipate nonperformance by the counterparties as all counterparties' credit ratings are in compliance with Basin Electric's, Dakota Gas', and Dakota Coal's risk policy requirements included in the Manual.

COLLATERAL — Certain derivative instruments of Basin Electric and Dakota Gas contain contract provisions that require collateral to be posted if the credit ratings of Basin Electric fall below certain levels or if the counterparty exposure to Basin Electric or Dakota Gas exceeds a certain level. Due to credit rating and counterparty exposure levels at December 31, 2017 and 2016, Basin Electric posted $119,716 and $114,787, and Dakota Gas posted $8,322 and $1,931 of collateral related to their derivative liabilities that contained credit-related contingent features. In the December 31, 2017 Consolidated Balance Sheets, collateral of $77,285 was included in Other investments, $42,000 was included in Other current assets, and $8,753 was included in Cash and cash equivalents. In the December 31, 2016 Consolidated Balance Sheets, collateral of $81,230 was included in Other investments, $32,607 was included in Prepayments and other current assets, and $2,881 was included in Cash and cash equivalents.

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE — ASC 820, Fair Value Measurements, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The standard applies to reported balances that are required or permitted to be measured at fair value.

ASC 820 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. As a basis for considering market participant assumptions in fair value measurements, ASC 820 establishes a fair value hierarchy that distinguishes between market participant assumptions based on market data obtained from sources independent of the reporting entity (observable inputs that are classified within Levels 1 and 2 of the hierarchy) and the reporting entity's own assumptions about market participant assumptions (unobservable inputs classified within Level 3 of the hierarchy).

Level 1 inputs utilize observable market data in active markets for identical assets or liabilities. Level 2 inputs consist of observable market data, other than that included in Level 1, that is either directly or indirectly observable. Level 3 inputs consist of unobservable market data which are typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity. In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. Basin Electric's 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.

On December 31, 2017 and 2016, Basin Electric had money market accounts, commercial paper, U.S. government obligations and equity securities included in Short-term investments, Mine related assets and Other investments, recorded at a fair value, using quoted prices in active markets for identical assets as the fair value measurement (Level 1).

On December 31, 2017 and 2016, Basin Electric recorded derivative financial instruments including commodity contracts and interest rate swaps and guaranteed investment certificates using significant other observable inputs as the fair value measurement (Level 2). The fair value for commodity contracts is determined by comparing the difference between the net present value of the cash flows for the commodity contracts at their initial price and the current market price. The initial price is quoted in the commodity contract and the current market price is corroborated by observable market data. The fair value for interest rate swap contracts is determined by comparing the difference between the net present value of the cash flows for the swaps at their initial fixed rate and the current market fixed rate. The initial fixed rate is quoted in the swap agreement and the current market fixed rate is corroborated by observable market data. The fair value for the guaranteed investment certificates is determined by the insurance company by discounting the related cash flows based on current yields of similar instruments with comparable durations considering the creditworthiness of the issuer.

On December 31, 2016, Basin Electric recorded a Dakota Gas tar oil contract at fair value using significant unobservable inputs as the fair value measurement (Level 3). The valuation of this contract involved management's judgment. The fair value for the commodity contract was determined by comparing the difference between the net present value of the cash flows for the contract at their initial price and the current market price based on volatility curves as of December 31, 2016.

Basin Electric continuously monitors the creditworthiness of the counterparties to its derivative contracts and assesses the counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Basin Electric's own credit risk when determining the fair value of derivative assets and liabilities, the impact of considering credit risk was immaterial to the fair value of derivative assets and liabilities presented in the Consolidated Balance Sheets.

The following table summarizes assets and liabilities measured at fair value on a recurring basis as of December 31, 2017, aggregated by the level in the fair value hierarchy within which those measurements fall:

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments:				
Guaranteed investment certificates	$ 477	$ -	$ 477	$ -
Money market	250,243	250,243	-	-
Corporate commercial paper	91,048	91,048	-	-
Investment funds	752	752	-	-
Preservation funds	250	250	-	-
Equity securities	893	893	-	-
Institutional Index Fund	52,770	52,770	-	-
500 Index Fund	9,042	9,042	-	-
Total Bond Market Index Fund	35,136	35,136	-	-
Intermediate-Term Treasury Fund	6,031	6,031	-	-
	446,642	446,165	477	-
Derivative financial instruments	12,406	-	12,406	-
Less amounts classified as current assets	(353,213)	(341,291)	(11,922)	-
	$ 105,835	$ 104,874	$ 961	$ -
Liabilities:				
Interest rate swaps	$ 79,213	$ -	$ 79,213	$ -
Derivative financial instruments	26,539	-	26,539	-
Less amounts classified as current liabilities	(13,643)	-	(13,643)	-
	$ 92,109	$ -	$ 92,109	$ -

The following table summarizes assets and liabilities measured at fair value on a recurring basis as of December 31, 2016, aggregated by the level in the fair value hierarchy within which those measurements fall:

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets:				
Investments:				
Guaranteed investment certificates	$ 744	$ -	$ 744	$ -
Money market	185,127	185,127	-	-
Corporate commercial paper	33,800	33,800	-	-
Canadian government bonds	1,446	1,446	-	-
Institutional Index Fund	33,809	33,809	-	-
500 Index Fund	8,863	8,863	-	-
Total Bond Market Index Fund	18,947	18,947	-	-
Intermediate-Term Treasury Fund	5,316	5,316	-	-
	288,052	287,308	744	-
Derivative financial instruments	8,036	-	8,036	-
Less amounts classified as current assets	(225,594)	(218,927)	(6,667)	-
	$ 70,494	$ 68,381	$ 2,113	$ -
Liabilities:				
Interest rate swaps	$ 81,771	$ -	$ 81,771	$ -
Derivative financial instruments	39,940	-	38,924	1,016
Less amounts classified as current liabilities	(32,165)	-	(31,149)	(1,016)
	$ 89,546	$ -	$ 89,546	$ -

Basin Electric evaluates the significance of transfers between levels based on the nature of the financial instrument and size of the transfer relative to total assets. For the year ended December 31, 2016, there was a transfer of $744 between Level 1 and Level 2 based on additional information available on the fair value of guaranteed investment certificates.

SUBSEQUENT EVENTS — Basin Electric considered events for recognition or disclosure in the consolidated financial statements that occurred subsequent to December 31, 2017 through March 13, 2018, the date the consolidated financial statements were available for issuance. Management is not aware of any material subsequent events that would require recognition or disclosure in the 2017 consolidated financial statements.

RECENTLY ISSUED ACCOUNTING STANDARD UPDATES — In May 2014, the FASB issued accounting guidance on the recognition of revenue from contracts with customers, which will supersede nearly all existing revenue recognition guidance under generally accepted accounting principles (GAAP). Under the new standard, entities will recognize revenue to depict the transfer of goods and services to customers in amounts that reflect the payment to which the entity expects to be entitled in exchange for those goods or services. The guidance also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows from an entity's contracts with customers. In August 2015, the FASB issued accounting guidance deferring the effective date by one year. The new guidance will be effective for Basin Electric in 2019. Early adoption is permitted and must be applied retrospectively using one of two prescribed methods. Management is currently evaluating the impact of adoption of this new guidance on our consolidated financial statements and disclosures.

In November 2015, the FASB issued accounting guidance on balance sheet classification of deferred income taxes. To simplify the presentation of deferred income taxes, the accounting guidance requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The new guidance will be effective for Basin Electric in 2018. Early adoption is permitted and may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. Management believes the adoption of this new guidance will not have a material impact on our consolidated financial statements and disclosures.

In January 2016, the FASB issued accounting guidance on recognition and measurement of financial assets and financial liabilities. The new guidance improves certain aspects of recognition, measurement, presentation and disclosure of financial instruments. The new guidance will be effective for Basin Electric in 2018. Early adoption of certain provisions of the accounting guidance is permitted as of the beginning of the fiscal year of adoption, however, early adoption of the remaining provisions of this accounting guidance is not permitted. Management believes the adoption of this new guidance will not have a material impact on our consolidated financial statements and disclosures.

In February 2016, the FASB issued new accounting guidance for leases. The new guidance increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. In January 2018, the FASB issued additional accounting guidance on leases, amending the guidance issued in 2016, to simplify the transition to the new guidance for land easements. The new guidance will be effective for Basin Electric in 2020. Early adoption of the accounting guidance is permitted and must be applied using a modified retrospective approach. Management is currently evaluating the impact of adoption of this new guidance on our consolidated financial statements and disclosures.

In August 2016, the FASB issued new accounting guidance for classification of certain cash receipts and cash payments on the statement of cash flows. The new guidance increases transparency and comparability among organizations by providing specific guidance on eight issues. The new guidance will be effective for Basin Electric in 2019. Early adoption of the accounting guidance is permitted and must be applied using a retrospective transition method. Management believes the adoption of this new guidance will not have a material impact on our consolidated financial statements and disclosures.

In November 2016, the FASB issued new accounting guidance for classification of restricted cash on the statement of cash flows. The new guidance reduces diversity in practice by providing specific guidance on the presentation of restricted cash and restricted cash equivalents in the statement of cash flows. The new guidance will be effective for Basin Electric in 2019. Early adoption of the accounting guidance is permitted and must be applied using a retrospective transition method. Management believes the adoption of this new guidance will not have a material impact on our consolidated financial statements and disclosures.

In March 2017, the FASB issued new accounting guidance to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost in financial statements. The new guidance requires components of net periodic pension cost and net periodic postretirement benefit costs that are currently aggregated and reported as part of compensation be disaggregated and reported separately. Only the service cost component may be reported as part of compensation, be included in income from operations and be eligible for capitalization. The other cost components must be reported separately in the income statement. The new guidance will be effective for Basin Electric in 2019. Early adoption of the accounting guidance is permitted as of the beginning of an annual period for which financial statements (interim or annual) have not been issued or made available for issuance and should be applied retrospectively. Management believes the adoption of this new guidance will not have a material impact on our consolidated financial statements and disclosures.

In August 2017, the FASB issued new accounting guidance with the objective of improving the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and to make improvements to simplify the application of the hedge accounting guidance. The amendments provided in the new guidance will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The amendments also expand and refine hedge accounting for both nonfinancial and financial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The new guidance will be effective for Basin Electric in 2020. Early adoption of the accounting guidance is permitted and the effect of the adoption should be reflected as of the beginning of the fiscal year of adoption. Management is currently evaluating the impact of adoption of this new guidance on our consolidated financial statements and disclosures.

ACCOUNTING STANDARD UPDATES ADOPTED — In July 2015, the FASB issued accounting guidance on simplifying the measurement of inventory. This update applies to entities that measure inventory using first-in, first-out (FIFO) or average cost. It requires that inventory be measured at the lower of cost or net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The new guidance was effective for Basin Electric in 2017, and required no change in the valuation of inventory.

In February 2018, the FASB issued new accounting guidance to allow a reclassification from accumulated other comprehensive income (loss) to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected. Early adoption of the accounting guidance is permitted for entities for reporting periods for which financial statements have not yet been made available for issuance, and Basin Electric adopted the new guidance in 2017. Basin Electric reclassified $2,904 from Accumulated other comprehensive income (loss) to Retained earnings of subsidiaries, $2,449, Other equity, $478, and Patronage capital, $23, in 2017.

3. LEASES

CAPITAL LEASES — Basin Electric, Dakota Gas, and Dakota Coal are the lessees of certain substation, mining equipment, and railcars under capital leases expiring from 2018 to 2050. The assets and liabilities under capital leases are recorded at the lesser of the present value of the minimum lease payments or the fair value of the asset. Property under capital leases as of December 31, 2017 included various substation and mining equipment with an original cost of $23,139. The assets are amortized over the lesser of their related lease terms or their estimated productive lives. Certain of the mining equipment under capital leases are subleased to Coteau, recorded as direct financing leases and eliminated in consolidation.

Minimum future lease payments under capital leases as of December 31, 2017 for each of the next five years and in the aggregate are:

Year	Amount
2018	$ 1,864
2019	1,286
2020	1,172
2021	1,925
2022	782
Thereafter	18,024
Total minimum lease payments	25,053
Less: Amount representing interest	11,209
Present value of net minimum lease payments	$ 13,844

Interest rates on capitalized leases vary from 2.29 percent to 5.14 percent and are imputed based on the lessor's implicit rate of return.

LEASING ARRANGEMENTS AS LESSEE — Basin Electric leases certain electric plant facilities, mining and related equipment and other operational assets under noncancelable operating leases with initial terms up to 35 years.

Minimum future lease payments under noncancelable operating leases for each of the next five years and in aggregate are:

Year	Amount
2018	$ 27,778
2019	25,868
2020	18,362
2021	3,503
2022	3,125
Thereafter	17,713
Total	$ 96,349

Rental payments charged to expense were $45,975 and $46,484 in 2017 and 2016.

4. JOINTLY OWNED FACILITIES

Basin Electric's investment in the MBPP electric plant was as follows at December 31:

	2017	2016
Electric plant	$ 790,356	$ 778,694
Less accumulated provision for depreciation and amortization	(516,385)	(505,649)
	$ 273,971	$ 273,045

Basin Electric's share of MBPP operating expenses was $116,610 and $116,736 for 2017 and 2016, and is reflected in utility operating expenses. Each of the members in MBPP are responsible for arranging their own financing for their ownership interest in MBPP.

5. MINE RELATED ASSETS

Assets associated with the properties that supply coal for AVS, LOS and Dakota Gas' Synfuels Plant are classified as Mine related assets and were as follows at December 31:

	2017	2016
Prepaid coal royalties	$ 30,574	$ 32,635
Mine closing fund investments	102,979	90,797
Interest on coal royalties	16,183	17,266
Notes receivable and mine financing costs	44	446
Other	4,946	5,327
	$ 154,726	$ 146,471

Coteau notes receivable with NACoal of $0 and $387 at December 31, 2017 and 2016 included above bear interest rates varying from 0.96 percent to 1.27 percent.

6. DEFERRED CHARGES

Deferred charges are recovered through amortization into service rates charged by Basin Electric to customers over periods ranging from 3 to 30 years or as tax timing differences reverse and were as follows at December 31:

	2017	2016
Regulatory asset related to deferred income taxes	$ 93,783	$ 61,264
Refinancing fees	129,517	135,692
Regulatory deferred pension expense	5,309	6,155
Unrealized loss on interest rate swaps	78,248	80,806
Unrealized loss on natural gas swaps	8,220	938
Other	19,193	21,358
	$ 334,270	$ 306,213

Interest on coal royalties and other costs deferred under ASC 980, totaling $21,130 and $22,593 at December 31, 2017 and 2016, are included in Mine related assets on the Consolidated Balance Sheets.

7. EQUITY

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) — The following table includes the changes in the balances of the components of Accumulated other comprehensive income (loss), net of tax, on the Consolidated Balance Sheets:

	Post Employment Benefit Plans	Unrealized Gain on Securities	Unrealized Gain (Loss) on Cash Flow Hedges	Total
Balance, December 31, 2015	$ (24,309)	$ 8,853	$ 8,903	$ (6,553)
Comprehensive income (loss)	5,669	3,201	(20,216)	(11,346)
Balance, December 31, 2016	(18,640)	12,054	(11,313)	(17,899)
Comprehensive income	5,318	5,494	6,524	17,336
Reclassification of accumulated other comprehensive income (loss) due to tax reform	349	3,388	(833)	2,904
Balance, December 31, 2017	$ (12,973)	$ 20,936	$ (5,622)	$ 2,341

OTHER EQUITY — From November 1981 through August 1983, Basin Electric sold approximately $894,000 of electric plant under sale and leaseback agreements in exchange for $310,000 in cash and $584,000 in notes. Annual lease payments are equal to the payments the purchaser is required to make on its notes to Basin Electric. The sale and lease transactions have not been recognized for financial reporting purposes, as such transactions were entered into solely for tax purposes under the Economic Recovery Tax Act of 1981 and the Tax Equity and Fiscal Responsibility Act of 1982 and do not affect Basin Electric's rights with respect to the property. The $310,000, net of expenses of $28,000, was reserved in Other equity.

Beginning in March 2001, Basin Electric allocated its before tax margin to members and recorded the provision for (benefit from) income taxes in Other equity. As of December 31, 2017, $18,733 of net income tax benefit was closed into Other equity.

8. LONG-TERM DEBT

	December 31, 2017	December 31, 2016
Basin Electric Power Cooperative, First Mortgage Bonds, 2006 Series A, due June 2041, interest at 6.127%	$ 200,000	$ 200,000
Basin Electric Power Cooperative, First Mortgage Obligations, CoBank 2007 Series Notes 1 and 2, due in quarterly installments through September 2042, interest at 4.02%, 4.37%, 5.92%, 6.24%, 6.27% and 6.59%	277,467	283,741
Basin Electric Power Cooperative, First Mortgage Obligations, 2009 Series C Notes, due in semi-annual installments through October 2027, interest at 4.89%	100,000	100,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2009 Series D Notes, due in semi-annual installments through April 2040, interest at 5.59%	110,000	110,000
Basin Electric Power Cooperative, Wyoming Infrastructure Authority Note, due in semi-annual maturities through September 1, 2025, interest at 4.84%	21,423	23,569
Campbell County Wyoming Solid Waste Facilities Revenue Bonds 2009 Series A, due in semi-annual installments through July 2039, interest at 5.75%	150,000	150,000
Basin Electric Power Cooperative, First Mortgage Obligations, CoBank 2005 Series A Note, due December 2028, interest at 5.85%	45,000	45,000
Basin Electric Power Cooperative, First Mortgage Obligations, CoBank 2005 Series B Note, due May 2030, interest at 5.85%	45,000	45,000
Basin Electric Power Cooperative, First Mortgage Note, Wells Fargo Note Number 1, due in annual installments through June 2027, interest at 5.395%	12,500	13,750
Basin Electric Power Cooperative, First Mortgage Obligations, Wells Fargo Note Number 2, due in annual installments through December 2028, interest at 4.745%	8,250	9,000
Basin Electric Power Cooperative, First Mortgage Obligations, MetLife 2008 Series A Note Number 1, due June 2030, variable interest at 3.003%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, MetLife 2008 Series A Note Number 2, due May 2032, variable interest at 3.095%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, MetLife 2008 Series A Note Number 3, due May 2032, variable interest at 3.152%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, MetLife 2008 Series A Note Number 4, due May 2032, variable interest at 3.168%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, New York Life 2008 Series B Note, due June 2029, variable interest at 3.032%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, John Hancock 2008 Series C Note, due June 2031, variable interest at 3.044%	50,000	50,000
Basin Electric Power Cooperative, First Mortgage Obligations, Prudential 2008 Series D Note, due in semi-annual installments through October 2038, interest at 5.93%	105,000	110,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2008 Series E Note, due in semi-annual installments through December 2028, interest at 7.69%	27,500	30,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2008 Series F Note, due in serial maturities through December 2038, interest at 8.20%	100,000	100,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2011 Series A Notes, due in semi-annual installments through October 2031, interest at 4.00%	217,780	229,230
Basin Electric Power Cooperative, First Mortgage Obligations, 2011 Series B Notes, due in semi-annual installments through October 2049, interest at 5.10%	100,000	100,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2012 Series A Notes, due in semi-annual installments through November 2044, interest at 4.067%	91,673	93,513
Basin Electric Power Cooperative, notes payable to affiliates, bullet maturities ranging from January 2018 to December 2019, interest at 1.42%	1,847	2,629
Basin Electric Power Cooperative, First Mortgage Obligations, 2015 Series A Notes, due in semi-annual installments through June 2027, interest at 3.74%	250,000	250,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2015 Series B Notes, due in semi-annual installments through June 2034, interest at 4.10%	285,000	285,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2015 Series BK Notes, due in semi-annual installments through June 2034, interest at 4.10%	40,000	40,000
Basin Electric Power Cooperative, First Mortgage Obligations, 2015 Series C Notes, due in semi-annual installments through June 2044, interest at 4.74%	925,000	925,000

Basin Electric Power Cooperative, First Mortgage Obligations, 2016 CoBank Note, due in semi-annual installments through April 2046, interest at 4.48%	95,000	98,333
Basin Electric Power Cooperative, First Mortgage Obligations, 2016 CFC Note, due in quarterly installments through April 2046, interest at 3.74%	71,849	74,370
Basin Electric Power Cooperative, First Mortgage Bonds, 2017 Series A, due April 2047, interest at 4.75%	500,000	-
Equipment notes, Series S, due in monthly installments through December 2020, interest at 6.26%	1,560	2,080
Equipment notes, Series X, due in monthly installments through February 2017, interest at 5.70%	-	34
Equipment notes, Series II, due in monthly installments through July 2020, interest at 6.03%	2,671	5,194
Equipment notes, Series LL and MM, due in monthly installments through November 2020, interest from 5.49% to 5.76%	4,467	7,077
Equipment notes, Series NN and PP, due in monthly installments through July 2020, interest from 2.97% to 3.42%	1,027	1,960
Equipment notes, Series TT and UU, due in monthly installments through July 2021, interest from 2.48% to 2.61%	1,432	1,843
Equipment notes, Series VV, WW and XX, due in monthly installments through November 2024, interest from 2.26% to 3.08%	4,204	4,872
Equipment notes, Series AAA, BBB and CCC, due in monthly installments through September 2022, interest from 2.62% to 3.49%	1,742	2,157
Equipment notes, Series DDD, EEE, FFF, GGG and HHH, due in monthly installments through December 2025, interest from 2.58% to 3.68%	2,942	3,472
Equipment notes, due in semi-annual installments through April 2032, interest at 4.10%	50,424	54,330
Equipment notes, Series III, JJJ and KKK, due in monthly installments through May 2026, interest from 2.77% to 3.28%	8,957	10,189
Equipment notes, Series LLL, MMM, NNN and OOO, due in monthly installments through December 2027, interest from 3.53% to 3.89%	21,849	-
Dakota Gasification Company, Senior Secured Notes, 2015 Series A Notes, due in semi-annual installments through May 2030, interest at 3.66%	50,000	50,000
Dakota Gasification Company, Senior Secured Notes, 2015 Series B Notes, due in semi-annual installments through May 2035, interest at 4.33%	200,000	200,000
Dakota Gasification Company, Senior Secured Notes, 2015 Series C Notes, due in semi-annual installments through May 2045, interest at 4.01%	225,000	225,000
Other	19,308	18,534
	4,675,872	4,204,877
Less:		
Current portion	(68,384)	(50,846)
Unamortized debt issue costs	(29,227)	(21,029)
	$ 4,578,261	$ 4,133,002

The estimated fair value of debt at December 31, 2017 and 2016 was $4,996,546 and $4,425,874, based on cash flows discounted at interest rates for similar issues or at the current rates offered to Basin Electric for debt of comparable maturities.

The scheduled maturities of long-term debt for the next five years at December 31, 2017 are as follows:

	2018	2019	2020	2021	2022
Long-term debt	$ 68,384	$ 101,470	$ 99,467	$ 98,632	$ 95,987

All of Basin Electric's long-term debt is secured under the Amended and Restated Indenture dated as of May 5, 2015 (the "Indenture"), between Basin Electric and U.S. Bank National Association, as trustee. Pursuant to the Indenture, Basin Electric created a first lien on substantially all of its tangible and certain of its intangible assets in favor of the Indenture trustee to secure certain long-term debt on a pro-rata basis.

Basin Electric's debt agreements contain various restrictive covenants which, among other matters, require Basin Electric to maintain a defined margins for interest ratio.

All of Dakota Coal's long-term debt is secured under the Third Amended and Restated Indenture of Trust and Security Agreement dated as of January 1, 1994 between Dakota Coal and Wells Fargo Bank, N.A., formerly known as Norwest Bank Minnesota, National Association, as trustee.

All of Dakota Gas' long-term debt is secured under an Indenture dated as of May 1, 2015 between Dakota Gas and U.S. Bank, National Association, as trustee. Dakota Gas' long-term debt is also backed by an unsecured Guarantee dated as of May 8, 2015 by Basin Electric, its parent, in favor of U.S. Bank, National Association, as Trustee.

9. INCOME TAXES

Basin Electric is a nonexempt cooperative subject to federal and state income taxation, but as a cooperative is allowed to exclude from income margins allocated as patronage capital. Basin Electric and its subsidiaries (the Consolidated Group) file a consolidated income tax return and have entered into tax-sharing agreements. Income taxes are allocated among members of the Consolidated Group based on a systematic, rational and consistent method under which such taxes approximate the amount that would have been computed on a separate company basis, subject to limitations on the Consolidated Group.

In accordance with the provisions of ASC 740, Income Taxes, Basin Electric records a liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of the liability for unrecognized tax benefits is as follows:

	2017	2016
Balance at January 1	$ 3,806	$ 900
Addition for tax positions of current period	1,159	872
Addition for tax positions of prior periods	903	2,034
Reduction for tax positions of prior periods	(184)	-
Balance at December 31	$ 5,684	$ 3,806

Basin Electric recognizes interest and penalties related to unrecognized tax benefits (if any) in the respective interest and penalties expense accounts and not in the Benefit from income taxes. There are no amounts of unrecognized tax benefits that are expected to significantly change within the next 12 months.

The components of Basin Electric's Benefit from income taxes were as follows for the years ended December 31:

	2017	2016
Current tax benefit	$ (9,650)	$ (9,612)
Tax benefit from subsidiary merger	(41,712)	-
Deferred tax benefit	(33,494)	(57,309)
Deferred tax benefit from federal tax rate change	(23,200)	-
Benefit from income taxes	$ (108,056)	$ (66,921)

Basin Electric accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that were included in the consolidated financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax bases of assets and liabilities by using enacted tax rates in effect for year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

On December 22, 2017, U.S. tax reform legislation was enacted that reduced the U.S. corporate tax rate to 21% effective January 1, 2018. As a result, the deferred tax assets and liabilities presented at December 31, 2017 were measured at the new 21% federal rate which will be in effect when the differences are expected to reverse. The effect of the change in rates on deferred tax assets and liabilities was recognized in 2017 and is separately stated as a component of the benefit from income taxes shown above.

The tax effect of significant temporary differences representing deferred tax assets and liabilities were as follows at December 31:

	2017	2016
Deferred tax liabilities:		
Depreciation and property	$ 248,802	$ 397,714
RUS refinancing expense	21,831	38,173
Direct financing leases	21,318	36,301
Other deferred tax liabilities	9,320	14,755
Unrealized gains	5,939	-
Total deferred tax liability	307,210	486,943
Deferred tax assets:		
Tax benefit transfer leases	(32,393)	(58,706)
Deferred revenue	(38,850)	(5,250)
Deferred credits	(10,764)	(15,346)
Tax credits available	(20,656)	(30,905)
Tax credit/charitable contribution valuation allowance	20,868	-
Mine related	(5,964)	(7,901)
Patronage loss carryforward	(60,083)	(139,298)
Net operating loss carryforward	(56,285)	(54,863)
Other deferred tax assets	(11,205)	(20,913)
Unrealized losses	(2,296)	(5,716)
Total deferred tax assets	(217,628)	(338,898)
Net deferred tax liability	89,582	148,045
Current deferred tax liability (asset)	257	(9,336)
Noncurrent deferred tax liability	$ 89,325	$ 157,381

Deferred taxes have been provided for temporary income tax differences associated with utility operations with an offsetting amount recorded as a regulatory asset as such amounts are expected to be recovered through rates charged to members at such time as the Board of Directors, in its capacity as regulator, deems appropriate. As a result of 2017 tax reform, the net deferred tax liabilities associated with utility operations decreased by $34,824 with an offsetting amount recorded to the regulatory asset. Additionally, in December 2017, PrairieWinds ND 1 and PrairieWinds SD 1 were merged with Basin Electric. The net deferred tax liabilities of the subsidiaries were transferred to Basin Electric and a regulatory asset and income tax benefit of $41,712 was recorded.

Income taxes differ from the Benefit from income taxes computed using the statutory rate for the years ended December 31 as follows:

	2017	2016
Computed income tax at statutory rate	$ (12,501)	$ (4,324)
Permanent differences:		
Patronage capital allocated	(25,241)	(49,269)
Other, net	254	(1,357)
Change in regulatory asset associated with deferred taxes net of patron net operating loss	(9,978)	(9,986)
Tax credit/charitable contribution valuation allowance for subsidiaries	4,023	-
Benefit from federal tax rate change for subsidiaries	(23,200)	-
Benefit from merger of subsidiary	(41,712)	-
Other	(37)	(611)
State income taxes	336	(1,374)
Benefit from income taxes	$ (108,056)	$ (66,921)

Basin Electric had available federal and state research tax credit carryforwards of approximately $20,656 and charitable contribution carryforwards of approximately $212 at December 31, 2017. The research tax credits expire in varying amounts from 2019 through 2038 and the charitable contribution carryforwards expire in varying amounts from 2018 through 2023. It is more likely than not that the benefit from certain federal and state tax credit and charitable contribution carryforwards will not be realized. In recognition of this risk, a valuation allowance on the deferred tax assets related to these tax credits and charitable contribution carryforwards was recorded in 2017.

Basin Electric has a consolidated net operating loss carryforward as of December 31, 2017 of $268,025. The net operating loss expires in varying amounts from 2035 through 2038. Basin Electric has a patron federal net operating loss carryforward of approximately $286,112. The patron net operating loss expires in varying amounts from 2031 through 2037. It is more likely than not that the benefit from net operating losses will be recognized before their expiration.

Basin Electric completed examinations by the Internal Revenue Service (IRS) through 2010. Management does not believe future settlements with the IRS will be material to Basin Electric's financial position.

10. EMPLOYEE BENEFIT PLANS

POSTRETIREMENT BENEFITS — Employees of Basin Electric, Dakota Gas, and MLC retiring at or after attaining age 55 and completing five years of service may elect to continue medical and dental benefits by paying premiums to Basin Electric, Dakota Gas or MLC for participating in the current employee plan, subject to deductible, coinsurance and copayment provisions. Eligible dependents of retired employees continue to receive benefits after the death of the former employee, with certain limitations. Participation in Basin Electric's, Dakota Gas' or MLC's medical plan can continue until the retiree or spouse becomes eligible for Medicare. Once a retiree becomes eligible for Medicare, the spouse may continue under each of the plans until the spouse becomes eligible for Medicare. Basin Electric, Dakota Gas, and MLC reserve the right to change or terminate these benefits at any time.

Basin Electric, Dakota Gas and MLC fund postretirement medical benefits from general funds, and in 2017 and 2016 funding was $2,504 and $1,998.

Coteau established a Voluntary Employees Beneficiary Association (VEBA) trust to provide for postretirement medical benefits other than pensions. The trust was terminated in 2017. No contributions to the VEBA trust were made in 2017 and 2016. Coteau also maintains medical care and life insurance plans which provide benefits to eligible retired employees.

Net periodic postretirement benefit expense for the years ended December 31 includes the following components:

	Basin Electric and Subsidiaries		Coteau	
	2017	2016	2017	2016
Service cost – benefits attributed to service during the year	$ 2,360	$ 3,099	$ 177	$ 311
Interest cost on accumulated postretirement benefit liability	1,269	1,798	364	540
Return on plan assets	-	-	(12)	(69)
Amortization of prior service cost (credit)	(390)	(456)	7	(137)
Amortization of unrecognized loss (gain)	(1,044)	(53)	-	679
Net periodic postretirement benefit expense	$ 2,195	$ 4,388	$ 536	$ 1,324
Other changes recognized in Other comprehensive income (loss):				
Net loss (gain) arising during the period	$ (12,386)	$ 4,328	$ (350)	$ (4,742)
Amortization of prior service credit (cost)	390	456	(7)	137
Amortization of gain (loss)	1,044	53	-	(679)
Total recognized in Other comprehensive income (loss)	$ (10,952)	$ 4,837	$ (357)	$ (5,284)

Assumptions used to determine net periodic postretirement benefit expense were as follows for the years ended December 31:

	Basin Electric and Subsidiaries		Coteau	
	2017	2016	2017	2016
Weighted-average discount rates	4.00%	4.22%	3.25%	3.40%
Expected long-term rate of return on plan assets	N/A	N/A	5.75%	5.75%
Health care cost trend rate assumed	6.78%	7.10%	7.00%	7.25%
Ultimate health care cost trend	4.50%	4.50%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2038	2038	2025	2025

The following sets forth the changes in accumulated postretirement benefit liability and plan assets during the year, and reconciles the funded status of the plans to the accrued liability which is included in Deferred credits, taxes and other liabilities on the Consolidated Balance Sheets, as of December 31:

	Basin Electric and Subsidiaries		Coteau	
	2017	2016	2017	2016
Change in accumulated postretirement benefit liability:				
Balance at January 1	$ 47,060	$ 39,832	$ 11,512	$ 16,104
Service cost	2,360	3,099	177	311
Interest cost	1,269	1,798	364	540
Actuarial loss (gain)	(13,834)	3,511	(435)	(4,819)
Assumption changes	1,448	818	-	-
Benefit payments	(5,562)	(4,821)	(682)	(624)
Plan participants' contributions	3,058	2,823	-	-
Balance at December 31	$ 35,799	$ 47,060	$ 10,936	$ 11,512
Change in plan assets:				
Fair value of plan assets at beginning of year	$ -	$ -	$ 708	$ 1,720
Actual return on plan assets	-	-	(73)	(8)
Employer contributions	2,504	1,998	-	-
Plan participants' contributions	3,058	2,823	47	-
Benefit payments	(5,562)	(4,821)	(682)	(1,004)
Fair value of plan assets at end of year	$ -	$ -	$ -	$ 708
As of December 31, the funded status of the plan was:				
Accumulated postretirement benefit liability	$ 35,799	$ 47,060	$ 10,936	$ 11,512
Fair value of plan assets	-	-	-	708
Funded status at end of year	$ 35,799	$ 47,060	$ 10,936	$ 10,804
Amounts recognized in the balance sheets consist of:				
Current liabilities	$ 2,086	$ 2,683	$ 988	$ 298
Noncurrent liabilities	33,713	44,377	9,948	10,506
Net amount recognized in balance sheet	$ 35,799	$ 47,060	$ 10,936	$ 10,804
Amounts not yet reflected in net periodic postretirement benefit expense and included in Accumulated other comprehensive income (loss):				
Prior service cost	$ (857)	$ (468)	$ (3)	$ (4)
Actuarial gain (loss)	14,396	3,055	(2)	(348)
Accumulated other comprehensive income (loss)	$ 13,539	$ 2,587	$ (5)	$ (352)

For Basin Electric and subsidiaries, as of December 31, 2017, $283 of the prior service credit and $821 of the actuarial gain will, through amortization, be recorded as components of net periodic postretirement benefit expense in 2018.

For Coteau, as of December 31, 2017, $3 of the prior service cost and $0 of the actuarial loss will, through amortization, be recorded as components of net periodic postretirement benefit expense in 2018.

Assumptions used in accounting for the postretirement benefit plans obligation were as follows for the years ended December 31:

	Basin Electric and Subsidiaries		Coteau	
	2017	2016	2017	2016
Weighted-average discount rates	3.57%	4.00%	3.10%	3.25%
Initial health care cost trend	6.47%	6.78%	6.75%	7.00%
Ultimate health care cost trend rate	4.50%	4.50%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2038	2038	2025	2025

Changes in the assumed health care cost trend rates would impact the accumulated postretirement benefit liability and the net periodic postretirement benefit expense for 2017 as follows:

	Basin Electric and Subsidiaries		Coteau	
	1% Increase	1% Decrease	1% Increase	1% Decrease
Accumulated postretirement benefit liability	$ 3,667	$ (3,248)	$ 758	$ (721)
Net periodic postretirement benefit expense	$ 480	$ (408)	$ 37	$ (35)

Postretirement benefit plan weighted average asset allocations for Coteau were as follows:

	Coteau	
	2017	2016
Equity securities	0%	59.0%
Debt securities	0%	35.6%
Other	0%	5.4%
	0%	100%

Basin Electric and its subsidiaries and Coteau expect to make contributions of $2,086 and $988 in 2018 to their postretirement medical plans.

The following are the expected future benefits to be paid:

	Basin Electric and Subsidiaries	Coteau
2018	$ 2,086	$ 988
2019	$ 2,179	$ 1,083
2020	$ 2,514	$ 1,202
2021	$ 2,678	$ 1,219
2022	$ 2,827	$ 1,284
2023-2027	$ 14,583	$ 5,361

DEFINED BENEFIT PLANS — Pension benefits for substantially all Basin Electric and Dakota Gas employees are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement Security Plan (RS Plan) which is a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue code. It is a multiemployer plan under the accounting standards.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

Basin Electric and Dakota Gas contributions to the RS Plan in 2017 and in 2016 represented less than 5 percent of the total contributions made to the plan by all participating employers. Pension costs charged to expense during 2017 and 2016 were $49,244 and $46,761. There have been no significant changes that affect the comparability of 2017 and 2016 contributions.

In the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act (PPA) of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at January 1, 2017 and 2016 based on the PPA funding target and PPA actuarial value of assets on those dates.

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

Certain of Basin Electric's employees participate in an Executive Benefit Restoration (EBR) Plan established in October 2015. The EBR Plan is a noncontributory defined benefit plan sponsored by Basin Electric. Benefits under the EBR plan are based on the difference between amounts without IRS qualified pension plan limits on compensation and benefits and those with such limits as determined under the provisions of the NRECA RS Plan.

Net periodic pension expense of Basin Electric associated with the EBR for the year ended December 31 include the following components:

	2017	2016
Service cost	$ 64	$ 32
Interest cost	66	53
Amortization of prior service cost	199	520
Amortization of loss	25	7
Adjustment of prior period	-	94
Net periodic pension expense	$ 354	$ 706

	2017	2016
Other changes recognized in Other comprehensive income (loss):		
Net loss arising during the period	$ (65)	$ -
Prior service cost arising during the period	(661)	-
Amortization of prior service cost	199	520
Amortization of actuarial loss	25	299
Adjustment of prior period	-	357
Total recognized in Other comprehensive income (loss)	$ (502)	$ 1,176

The assumptions used to determine net periodic pension expense were as follows for the years ended December 31:

	2017	2016
Weighted average discount rate	3.68%	4.06%

Basin Electric expects to make no contributions in 2018.

At December 31, 2017, Basin Electric expects to pay benefits for the next five years and thereafter as follows:

2018	2019	2020	2021	2022	Thereafter
$ 52	$ 1,319	$ -	$ -	$ -	$ 1,912

The following sets forth the changes in the pension benefit obligation based on the actuary's analysis as of December 31:

	2017	2016
Change in pension benefit obligation:		
Projected benefit obligation at January 1	$ 1,053	$ 694
Adjustment to December 31, 2015	-	452
Adjusted projected benefit obligation at January 1	1,053	1,146
Service cost	64	32
Interest cost	66	53
Plan amendments	661	-
Actuarial loss	65	292
Benefit payments	-	(470)
Projected pension benefit obligation at end of year	$ 1,909	$ 1,053
As of December 31, the funded status of the plan was as follows:		
Projected benefit obligation	$ 1,909	$ 1,053
Fair value of plan assets	-	-
Funded status at end of year	$ 1,909	$ 1,053
Amounts recognized in the balance sheets consist of:		
Current liabilities	-	-
Noncurrent liabilities	1,909	1,053
Net amount recognized	$ 1,909	$ 1,053
Amounts not yet reflected in net periodic pension expense and included in Accumulated other comprehensive income (loss):		
Prior service cost	$ 946	$ 483
Actuarial loss	317	278
Accumulated other comprehensive income (loss)	$ 1,263	$ 761

The projected pension benefit obligation included in the table above represents the actuarial present value of benefits attributable to employee service rendered to date, including the effects of estimated future pay increases. The accumulated pension benefit obligation also reflects the actuarial present value of benefits attributable to employee service rendered to date, including the effects of estimated future pay increases.

As of December 31, 2017, $199 of the prior service cost and $25 of the actuarial loss will, through amortization, be recorded as components of net periodic pension expense in 2018.

Assumptions used to account for the pension benefit obligation were as follows for the years ended December 31:

	2017	2016
Weighted average discount rate	3.69%	3.68%
Rate of increase in compensation levels	1.50%	1.50%

BCS's former United Mine Workers of America employees are covered under a defined benefit plan which is funded by BCS. Plan assets are invested in common stocks, long-term corporate bonds and money market funds. BCS uses a December 31 measurement date.

Substantially all of Coteau's salaried employees hired prior to January 1, 2000, participate in NACoal's Salaried Employees Pension Plan (the NACoal Plan), a noncontributory defined benefit plan sponsored by NACoal. Benefits under the defined benefit pension plan are based on years of service and average compensation during certain periods.

During 2013, Coteau amended the Combined Defined Benefit Plan to freeze pension benefits for all employees effective as of the close of business on December 31, 2013. Employees whose benefits were frozen will receive retirement benefits under defined contribution retirement plans.

Effective December 31, 2014, current and former employees of Coteau participating in the Combined Defined Benefit Plan were "spun-off" into the new Coteau Pension Plan.

Net periodic pension expense for the years ended December 31 includes the following components:

	BCS		Coteau	
	2017	2016	2017	2016
Interest cost	$ 158	$ 176	$ 3,604	$ 3,872
Return on plan assets	(220)	(247)	(6,142)	(5,966)
Amortization of actuarial loss	112	122	182	229
Net periodic pension expense (income)	$ 50	$ 51	$ (2,356)	$ (1,865)
Other changes recognized in Other comprehensive income (loss):				
Net gain arising during the period	$ (57)	$ (166)	$ (2,180)	$ (1,080)
Amortization of actuarial loss	(112)	(122)	(182)	(229)
Total recognized in Other comprehensive income (loss)	$ (169)	$ (288)	$ (2,362)	$ (1,309)

The assumptions used to determine net periodic pension expense were as follows for the years ended December 31:

	BCS		Coteau	
	2017	2016	2017	2016
Weighted average discount rate	3.66%	3.80%	4.05%	4.30%
Expected long-term return on plan assets	6.25%	7.00%	7.50%	7.50%

The expected long-term rate of return on NACoal Plan assets reflects management's expectations of long-term rates of return on funds invested to provide for benefits included in the projected benefit obligations. NACoal has established the expected long-term rate of return assumption for NACoal Plan assets by considering historical rates of return over a period of time that is consistent with the long-term nature of the underlying obligations of the NACoal Plan. The historical rates of return for each of the asset classes used by NACoal to determine its estimated rate of return assumption were based upon the rates of return earned by investments in the equivalent benchmark market indices for each of the asset classes.

The following sets forth the changes in the pension benefit obligation and plan assets allocated based on the actuary's analysis as of December 31:

	BCS		Coteau	
	2017	2016	2017	2016
Change in pension benefit obligation:				
Projected benefit obligation at beginning of year	$ 4,498	$ 4,820	$ 90,747	$ 91,761
Interest cost	158	176	3,604	3,872
Actuarial loss (gain)	139	(128)	4,259	(1,422)
Benefits payments	(352)	(370)	(3,907)	(3,464)
Projected pension benefit obligation at end of year	$ 4,443	$ 4,498	$ 94,703	$ 90,747
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 3,700	$ 3,724	$ 80,485	$ 78,325
Actual return on plan assets	416	285	12,582	5,624
Employer contribution	-	61	-	-
Benefits payments	(352)	(370)	(3,907)	(3,464)
Fair value of plan assets at end of year	$ 3,764	$ 3,700	$ 89,160	$ 80,485
As of December 31, the funded status of the plan was as follows:				
Projected pension obligation	$ 4,443	$ 4,498	$ 94,703	$ 90,747
Fair value of plan assets	3,764	3,700	89,160	80,485
Funded status at end of year	$ 679	$ 798	$ 5,543	$ 10,262
Amounts recognized in the balance sheets consist of:				
Current liabilities	$ -	$ -	$ -	$ -
Noncurrent liabilities	679	798	5,543	10,262
Net amount recognized	$ 679	$ 798	$ 5,543	$ 10,262
Amounts not yet reflected in net periodic pension expense and included in Accumulated other comprehensive income (loss):				
Actuarial loss	$ 1,991	$ 2,160	$ 14,167	$ 16,529

The projected pension benefit obligation included in the table above represents the actuarial present value of benefits attributable to employee service rendered to date, including the effects of estimated future pay increases. The accumulated pension benefit obligation also reflects the actuarial present value of benefits attributable to employee service rendered to date, but does not include the effects of estimated future pay increases.

As of December 31, 2017, $357 of the Coteau actuarial loss and $112 of the BCS actuarial loss will, through amortization, be recorded as components of net periodic pension expense in 2018.

Assumptions used to account for the pension benefit obligation were as follows for the years ended December 31:

	BCS		Coteau	
	2017	2016	2017	2016
Weighted average discount rate	3.27%	3.66%	3.60%	4.05%

The NACoal Plan maintains an investment policy that, among other things, establishes a portfolio asset allocation methodology with percentage allocation bands for individual asset classes. The investment policy further divides investments in equity securities among U.S. and non-U.S. companies. The investment policy provides that investments are reallocated between asset classes as balances exceed or fall below the appropriate allocation bands.

The following is the actual and target allocation percentages for the NACoal Plan assets at the measurement date:

	2017 Actual Allocation	Target Allocation Range
U.S. equity securities	47.1%	36.0% – 54.0%
Non-U.S. equity securities	21.0%	16.0% – 24.0%
Fixed income securities	31.6%	30.0% – 40.0%
Money market	0.3%	0.0% – 10.0%
	100.0%	

The following is the actual and target allocation percentages for the BCS Plan assets at the measurement date:

	2017 Actual Allocation	Target Allocation Range
Equity securities	46.9%	37.0%
Fixed income securities	50.9%	60.0%
Other	2.2%	3.0%
Money market	100.0%	100.0%

BCS Plan assets are invested with a trust that is responsible for maintaining an appropriate investment ratio in common stocks, long-term corporate bonds and money market funds.

BCS and Coteau expect to make no contributions in 2018 to their defined benefit plans. The following are the expected future benefit payments for the BCS Plan and the Coteau Pension Plan:

	BCS	Coteau
2018	$ 341	$ 3,850
2019	$ 333	$ 4,141
2020	$ 324	$ 4,475
2021	$ 315	$ 4,813
2022	$ 306	$ 5,064
2023-2027	$ 1,401	$ 27,639

DEFINED CONTRIBUTION PLANS — Basin Electric, Dakota Gas and MLC have qualified tax deferred savings plans for eligible employees. Eligible participants of the tax deferred savings plans may make pre-tax and post-tax contributions, as defined, with Basin Electric, Dakota Gas and MLC matching various percentages of the participants' annual compensation. Contributions to these plans by Basin Electric, Dakota Gas, and MLC were $11,674 and $11,238 for 2017 and 2016.

For employees hired after December 31, 1999, Coteau established a defined contribution plan which requires Coteau to make retirement contributions based on a formula using age and salary as components of the calculation. Employees are vested at a rate of 20 percent for each year of service and are 100 percent vested after five years of employment. Coteau recorded contribution expense of approximately $2,698 and $2,593 related to this plan in 2017 and 2016.

Substantially all of Coteau's salaried employees also participate in a defined contribution plan sponsored by NACoal. Employee contributions are matched by Coteau up to a limit of 5 percent of the employee's salary. Coteau's contributions to this plan were approximately $2,318 and $2,219 in 2017 and 2016.

Under the provisions of the lignite sales agreement between Dakota Coal and Coteau, retirement related costs will be recovered as a cost of coal as tonnage is sold.

11. DEFERRED CREDITS, TAXES AND OTHER LIABILITIES

Deferred credits, taxes and other liabilities were as follows at December 31:

	2017	2016
Regulatory deferred revenue	$ 192,884	$ 22,884
Asset retirement obligations and other reserves	114,628	113,580
Long-term hedge liability	92,109	89,547
Non-current deferred income tax liability, net	89,325	157,381
Pension and benefit obligations	70,574	85,325
MBPP operating advances	40,207	29,207
Regulatory deferred post-retirement obligation	9,140	1,963
Other	8,206	5,238
Unearned revenue	2,399	2,742
	$ 619,472	$ 507,867

12. COMMITMENTS AND CONTINGENCIES

POWER PURCHASE COMMITMENTS — Basin Electric entered into various power purchase contracts from one to 25 years. The estimated commitments under these contracts as of December 31, 2017 were $389,652 in 2018, $360,358 in 2019, $365,523 in 2020, $321,162 in 2021, $303,124 in 2022, and $5,469,237 thereafter. Amounts purchased under the contracts totaled $352,026 in 2017 and $293,101 in 2016.

Basin Electric entered into various power purchase agreements with its Class A member, Corn Belt Power Cooperative (Corn Belt), under which Basin Electric buys substantially all of the output from Corn Belt's generation resources at cost, which approximates market, through December 2050. Basin Electric also entered into a transmission lease agreement with Corn Belt which expires in December 2050. ASC 810, Consolidation, requires that certain of Corn Belt's generation assets and liabilities associated with the power purchase agreements be consolidated in Basin Electric's Consolidated Balance Sheets. At December 31, 2017 and 2016, the assets and liabilities of Corn Belt included in the Consolidated Balance Sheets totaled $19,590 and $15,268. Basin Electric accounts for the costs associated with these assets and liabilities as operation, maintenance, interest and depreciation expense, rather than purchased power expense.

CONSTRUCTION CONTRACT COMMITMENTS — Basin Electric is constructing multiple transmission projects and a building addition to the headquarters in Bismarck. Dakota Gas is constructing a urea plant and capital projects for operational improvements. Various outstanding contractual construction commitments for Basin Electric and its subsidiaries totaled $118,635 as of December 31, 2017.

Coteau has outstanding equipment commitments of $9,719 as of December 31, 2017.

INVENTORY PURCHASE COMMITMENTS — Coteau entered into various diesel fuel contracts through January 2018. The estimated commitments under these purchase contracts as of December 31, 2017 were $280.

MINE CLOSING COSTS AND COAL PURCHASE COMMITMENTS — Under the terms of the Coteau Lignite Sales Agreement (Agreement) between Dakota Coal and Coteau, Dakota Coal is obligated to purchase all of its lignite requirements from Coteau, and Coteau is obligated to sell and deliver the required coal to Dakota Coal from contractually defined dedicated coal reserves. The coal purchase price includes all costs incurred by Coteau for development and operation of the dedicated coal reserves and may include costs to be incurred in connection with the Freedom Mine closing. During 2017 and 2016, Dakota Coal paid $206,234 and $198,904 to Coteau for coal purchased under the lignite sales agreement. As a result of applying ASC 810, Consolidation, Coteau is consolidated with Dakota Coal and coal purchases from Coteau are eliminated within the consolidated financial statements.

Under certain federal and state regulations, Coteau is required to reclaim land disturbed as a result of mining. Reclamation of disturbed land is a continuous process throughout the term of the Agreement. Costs of ongoing reclamation are charged to expense in the period incurred and are being recovered as a cost of coal as tonnage is sold to Dakota Coal. Costs to complete reclamation after mining has been completed in a specific mine area are reimbursed under the Agreement as costs of reclamation are actually incurred.

Coteau accounts for its asset retirement obligations under ASC 410, Asset Retirement and Environmental Obligations, which provides accounting requirements for retirement obligations associated with tangible long-lived assets and requires that an asset's retirement cost be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Coteau's annual costs related to amortization of the asset and accretion of the liability totaled $4,953 and $3,866 in 2017 and 2016.

Dakota Coal has established designated funds for mine closing costs. The Agreement includes provisions whereby, upon expiration of the agreement, Dakota Coal has the option to purchase the outstanding common stock of Coteau for its book value from NACoal. Dakota Coal may exercise this option only if Coteau has not exercised its right to extend the Agreement. NACoal has the option to require Dakota Coal to purchase the outstanding stock of Coteau for its book value in the event all of the plants Dakota Coal presently sells lignite coal to are closed or if lignite coal may no longer be legally mined in North Dakota and Dakota Coal exercises its right to terminate the Agreement with Coteau.

COAL PURCHASE AND FINANCING COMMITMENTS — Basin Electric, on behalf of the MBPP, has executed an agreement with Western Fuels Association, Inc. (Western Fuels) requiring coal purchases of approximately 5,900,000 tons per year through 2034, with an option to extend the contract with approval by both parties. The average price of coal under this agreement during 2017 and 2016 was approximately $18.13 and $18.49 per ton.

Basin Electric executed an agreement with Western Fuels requiring coal purchases of approximately 1,800,000 tons per year beginning in 2011 through the life of the DFS, with an option to extend the contract with approval by both parties. Coal purchased under this agreement is used at the DFS. The average price of coal purchased under this agreement during 2017 and 2016 was approximately $10.32 and $10.18 per ton.

The MBPP provides financing to Western Fuels and Western Fuels-Wyoming, Inc. (WFW), a wholly owned subsidiary of Western Fuels for mine development costs associated with coal deliveries to LRS. Basin Electric provides financing to Western Fuels and WFW for mine development costs associated with coal deliveries to DFS.

Notes receivable from Western Fuels and WFW are included in Other investments as of December 31, 2017 and 2016 and are as follows:

Issue date	Term	Interest Rate	Original Loan Value	Borrower	Purpose	2017	2016
12-15-10	32 years	5.15%	20,457	WFW	Coal conveyance equipment-DFS	$ 18,925	$ 19,277
05-03-11	7 years	5.61%	109	WFW	Mine capital spares- LRS Basin share	11	29
05-03-11	7 years	5.61%	180	WFW	Mine capital spares-DFS	18	48
12-30-11	7 years	4.35%	257	WFW	Mine capital spares-DFS	45	85
12-30-11	5 years	3.85%	445	WFW	Mine inventory spares - DFS	-	445
05-16-14	7 years	5.08%	2,366	WFW	Equipment purchase - LRS Basin share	1,155	1,493
09-19-14	7 years	4.99%	6,165	WFW	Equipment purchase - LRS Basin share	3,996	4,819
11-10-15	5 years	4.72%	761	WFW	Land purchase - LRS Basin share	467	612
02-16-16	7 years	4.51%	3,208	WFW	Equipment purchase - LRS Basin share	1,698	1,983
06-22-16	6.83 years	4.4633%	2,244	WFW	Equipment purchase-LRS Basin share	1,822	2,108
10-20-16	10 years	4.7556%	1,976	WFW	Road relocation project-LRS Basin share	1,794	1,954
						29,931	32,853
					Less current portion	(2,563)	(2,923)
						$ 27,368	$ 29,930

The estimated fair value of these notes receivable at December 31, 2017 and 2016 was $30,767 and $32,970, respectively, based on the future cash flows discounted using the yield on a treasury note with a similar maturity.

COAL SALES & PURCHASE COMMITMENT — In 2013, Basin Electric entered into agreements with three, unrelated companies to supply "refined coal" to AVS, LOS and LRS. The refined coal is produced by chemically treating lignite or sub-bituminous coal to produce a fuel stock which reduces air emissions during combustion of the treated coal. Basin Electric sells untreated coal to the refined coal supplier and then purchases refined coal from the supplier after it has been refined. The supplier pays Basin Electric for rent and services provided by Basin Electric in connection with supplier's production of refined coal. The estimated net benefit to Basin Electric for the refined coal projects through 2017 exceeds $15,000 per year. The refined coal suppliers own the coal treatment facilities, which were installed on the AVS, LOS and LRS plant sites and pay all associated operating costs. The refined coal suppliers qualify for certain federal tax credits for each ton of refined coal sold to Basin Electric with the reasonable expectation that it will be used for the purpose of producing steam and results in required emission reductions. Basin Electric has an option to purchase the coal treatment facilities (or similar assets) at each plant site after the eligible federal tax credit period ends in 2021. The agreements between the refined coal suppliers and Basin Electric allow for either party to terminate the agreement at any time, which would require the removal of the equipment at the refined coal supplier's cost.

ASSET RETIREMENT OBLIGATIONS — An asset retirement obligation is the result of legal or contractual obligations associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and/or the normal operation of a long-lived asset. Basin Electric and Coteau determine these obligations based on an estimated asset retirement cost adjusted for inflation and projected to the estimated settlement dates, and discounted using a credit-adjusted risk-free interest rate.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation included in Deferred credits, taxes and other liabilities on the Consolidated Balance Sheets is as follows:

	2017	2016
Balance, January 1	$ 104,967	$ 88,736
Liabilities settled during the period	(3,317)	(1,143)
Accretion expense	4,910	4,747
Addition (reduction) for utility obligations	(847)	12,627
Balance, December 31	$ 105,713	$ 104,967

RECLAMATION GUARANTEES — Basin Electric provides guarantees of certain reclamation obligations of Coteau. These guarantees cover the reclamation of mined areas as required by the State of North Dakota's Public Service Commission (PSC). The bonds are released by the PSC after a period of time (generally ten years after final reclamation is completed) when it has been determined that the mined area has been returned to its original condition. As of December 31, 2017, the aggregated value of these guarantees is $146,000.

Basin Electric provides guarantees of certain reclamation obligations of WFW. Those guarantees cover the reclamation of mined areas as approved by the Wyoming Department of Environmental Quality (WDEQ) under its self-bonding program. The bonds are released by the WDEQ after a period of time (generally ten years after final reclamation is completed) when it has been determined that the mined area has been returned to its approved post-mining use. As of December 31, 2017, the aggregated value of these guarantees is $14,700.

DISMANTLEMENT COSTS — The county zoning permit requires Dakota Gas to dismantle the Synfuels Plant at such time that operations or other alternative uses approved by the Board of County Commissioners are terminated. Although Dakota Gas presently intends to operate the Synfuels Plant indefinitely, in accordance with ASC 410, Asset Retirement and Environmental Obligations, Dakota Gas accrues an obligation for the eventual dismantlement and discontinuation of use of the Synfuels Plant.

LINES OF CREDIT — Basin Electric and Dakota Gas have entered into lines of credit which are included in Notes payable as follows:

Lender	Maturity	Total Availability		Outstanding Advances as of December 31, 2017	
CFC	03-18-18	$	130,000	$	129,925
Syndicate of Ten Banks	11-14-19	$	500,000	$	249,423
Syndicate of Thirteen Banks	12-12-22	$	500,000	$	-
Royal Bank of Canada	06-30-20	$	100,000	$	99,300

As of December 31, 2017, the effective interest rate of the outstanding advances is 1.37%.

LEASE INDEMNIFICATIONS — In general, under the terms of Basin Electric's sale and leaseback agreements discussed in Note 7, the lessors are indemnified should certain disqualifying events occur resulting in the recapture of tax credits, accelerated cost recovery deductions and interest deductions. Management believes that if indemnification occurs, there will not be a material adverse effect on Basin Electric's financial position, results of operations or cash flows.

CO_2 SALES COMMITMENTS — Dakota Gas has two contracts involving commitments for the sale of CO_2. One of these contracts is to sell and deliver CO_2 from the Synfuels Plant to oil fields located near Weyburn, Saskatchewan. The Weyburn agreement was for a 15-year term ended April 2016, which may be extended by the buyer with at least 120 days prior written notice for up to ten one-year renewals. The buyer has elected to extend the agreement for a second one-year renewal. If the buyer, over the course of a contract year, fails to take an average stated volume, Dakota Gas has the right to terminate this agreement 30 days following such contract year unless the buyer provides written notice to extend the agreement and pays Dakota Gas a penalty fee for each month the average stated volume was not taken.

The second CO_2 agreement is to sell and deliver CO_2 from the Synfuels Plant to oil fields located near Midale, Saskatchewan for a 20-year period ending in 2025, and required that this buyer pay a certain portion of Dakota Gas' additional capital requirements up front, reducing Dakota Gas' capitalized equipment cost. This buyer can terminate this agreement without penalty by giving 120 days prior written notice. If the initial Weyburn agreement is terminated, Dakota Gas has the right to terminate this Midale agreement by giving the buyer 120 days prior written notice.

CLEAN POWER PLAN — On October 23, 2015, the Environmental Protection Agency (EPA) published the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule (the Rule). The Rule establishes guidelines for states to develop plans to reduce CO_2 emissions from fossil fuel-fired electric generating units. In those states where Basin Electric owns and operates a substantial amount of fossil fuel-fired generation (North Dakota and Wyoming), the required reductions to be achieved by 2030 are substantial (45% and 44%, respectively).

Basin Electric filed a request with the EPA for an administrative stay pending judicial review and a petition for reconsideration of the Rule on October 30, 2015. The EPA denied Basin Electric's request for administrative stay and petition for reconsideration on January 11, 2017.

Basin Electric also filed with the D.C. Circuit Court a petition for review of the Rule on October 29, 2015 and a motion to stay the Rule on November 5, 2015. The D.C. Circuit consolidated the petitioners for judicial efficiency. The D.C. Circuit denied the consolidated petitioners' motions to stay the Rule on January 21, 2016. The consolidated petitioners then appealed to the Supreme Court of the United States via emergency petition on January 26, 2016. The Supreme Court granted the petitioners' request to stay the Rule on February 9, 2016. Oral arguments were held on September 27, 2016. The D.C. Circuit has yet to rule on the merits of the appeal of the Rule.

Unlike prior EPA Clean Air Act (CAA) regulations, the determination of what steps must be taken to comply with the Rule is the responsibility of state environmental agencies and not individual utilities. Thus it is difficult, if not impossible, to provide an accurate forecast of the likely cost of compliance if the Rule survives judicial scrutiny. Subject to that caveat, Basin Electric believes if the Rule is upheld by the courts, these costs would be substantial.

LARAMIE RIVER STATION BART FOR REGIONAL HAZE — The Regional Haze provisions of the CAA require that facilities that commenced construction between 1962 and 1977 identify and apply Best Available Retrofit Technology (BART) to control sulfur dioxide (SO_2) and nitrous oxide (NOx) emissions if their emission rates for those pollutants exceed certain threshold levels. All three LRS units exceed the presumptive levels for NO_x under the BART guidelines promulgated by the EPA in 2005. Basin Electric engaged in negotiations with the Wyoming Department of Environmental Quality (DEQ) from 2007 to 2009 relating to the NO_x emission levels for all three LRS units and the associated emission controls to operate LRS within the designated levels. The DEQ issued its BART determination in 2009. Under the Wyoming State Implementation Plan (SIP), LRS was required to install over-fire air technology to reduce NO_x emissions below the presumptive level for Unit 1 in 2009, Unit 2 in 2010 and Unit 3 in 2011 and to also install new "Low-NO_x burners" for Unit 1 in 2012, Unit 2 in 2013 and Unit 3 in 2014. These controls were installed at LRS in accordance with the scheduled outlined in the Wyoming SIP.

The EPA published its final rule on January 30, 2014, disapproving the Wyoming SIP for NO_x controls at LRS. The EPA's Federal Implementation Plan (FIP) instead required installation of Selective Catalytic Reduction (SCR) equipment on all three LRS units by March 2019 in order to meet a NO_x emission limit of 0.07 pounds per million British thermal units (BTU) on a thirty day rolling average.

On March 31, 2014, Basin Electric filed a Petition for Review with the 10th Circuit Court of Appeals (10th Circuit) of the EPA's NO_x determination requiring the installation of three SCRs at LRS. The 10th Circuit granted a stay on September 9, 2014 that extends the time for compliance for the duration of the litigation. This appeal is ongoing. Through the 10th Circuit Mediation Office, Basin Electric and the EPA have negotiated a tentative settlement, published in the Federal Register on December 30, 2016. The technology package includes SCR equipment on Unit 1, operational by July 31, 2019; and selective non-catalytic reduction equipment (SNCR) on Unit 2 and Unit 3, operational by December 31, 2018. The estimated cost of the technology package is $215 million for the SCR and $40 million for the two SNCRs. The settlement is not final until the EPA revises its FIP as it relates to LRS. The settlement is expected to be final in the summer of 2018. Until that time, the EPA could back out for numerous reasons in which case the litigation in the 10th Circuit would likely resume.

ENVIRONMENTAL PROTECTION AGENCY SECTION 114(A)-LRS — In September 2011, Basin Electric received a Section 114(a) letter from the EPA requesting information about certain projects at LRS. Responsive documents were submitted and the EPA responded by requesting additional information on twenty-five specific projects. The EPA subsequently contacted Basin Electric regarding specific work that was performed on the Unit 3 superheater in 2011. Discussions have been conducted with the EPA regarding whether this work constituted ordinary maintenance or constituted capital improvements that required a permit to construct. Basin Electric and the EPA Region 8 Enforcement have conducted confidential discussions and have signed a tolling agreement extending the statute of limitations for the Unit 3 superheater investigation to March 31, 2018. Discussions with EPA of whether the work was routine maintenance or a capital improvement are ongoing. LRS personnel conducted optimization studies and computational fluid dynamics modeling of the current system at LRS Unit 3 to determine whether the unit can achieve lower SO_2 emissions with the current controls instead of through installation of a capital project such as a baghouse or wet scrubber.

13. RELATED PARTY TRANSACTIONS

Other receivables include $3,390 and $1,272 at December 31, 2017 and 2016, for amounts Basin Electric, as operating agent, and its subsidiaries, have billed to MBPP. Included in Special funds on the Consolidated Balance Sheets is Basin Electric's advance to MBPP of approximately $16,995 and $12,346 at December 31, 2017 and 2016.

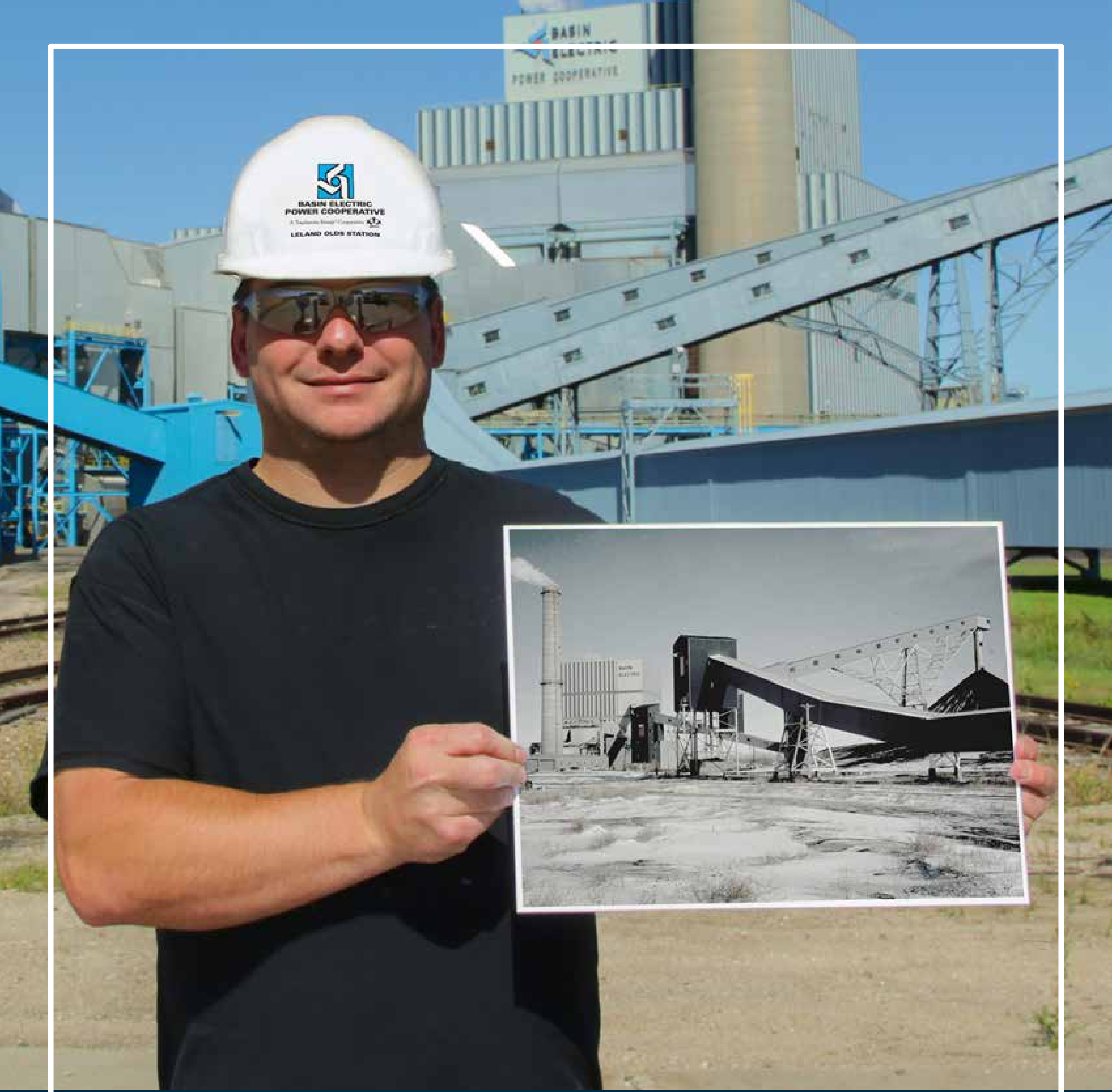
CONTRACTUAL COMMITMENTS — Basin Electric provides and receives power, various materials, supplies and services to and from affiliates which are under the following agreements through 2020, except as noted below:

- POWER SUPPLY — Basin Electric provides all electric capacity, energy and transmission service needed to meet Dakota Gas' Synfuels Plant requirements under an agreement that extends through 2050.
- POWER SALES — PrairieWinds ND and PrairieWinds SD sold electric power to Basin Electric under an agreement that ended in 2017.
- SCREENED COAL — Dakota Gas' Synfuels Plant provides screened coal to Basin Electric under an agreement that extends through 2037.
- COAL SUPPLY — Dakota Coal provides all coal requirements of Dakota Gas' Synfuels Plant and Basin Electric's AVS. It also supplies a majority of LOS's coal requirements. This agreement extends through 2037.
- ADMINISTRATIVE SERVICES — Basin Electric provides various administrative and financial services to Dakota Gas, Dakota Coal, PrairieWinds ND and PrairieWinds SD.
- LIME SALES — Dakota Coal provides lime to Basin Electric's AVS and LRS.
- LIMESTONE SALES — Dakota Coal provides limestone to Basin Electric's LOS.
- WATER SUPPLY — Basin Electric provides water supply facilities for use by Dakota Gas' Synfuels Plant.
- SALE OF NATURAL GAS — Dakota Gas sells natural gas to Basin Electric for operation of utility peaking plants and AVS.
- PROJECT SERVICES — Basin Electric provides the use of operational assets to Dakota Gas' Synfuels Plant.

Related party amounts that were not eliminated in consolidation in accordance with ASC 980, Regulated Operations, were billed as follows for the years ended December 31:

	2017	2016
Power supply from Basin Electric to Dakota Gas	$ 54,391	$ 47,708
Power sales from PrairieWinds ND to Basin Electric	$ 16,426	$ 15,953
Power sales from PrairieWinds SD to Basin Electric	$ 20,352	$ 22,394
Screened coal sales from Dakota Gas to Basin Electric	$ 58,334	$ 57,136
Coal supply sales from Dakota Coal to Basin Electric	$ 66,794	$ 58,575
Administrative services by Basin Electric to Dakota Gas	$ 23,960	$ 23,513
Administrative services by Basin Electric to Dakota Coal	$ 1,871	$ 1,378
Administrative services by Basin Electric to PrairieWinds ND	$ 960	$ 1,001
Administrative services by Basin Electric to PrairieWinds SD	$ 1,343	$ 1,306
Lime sales from Dakota Coal to Basin Electric	$ 11,750	$ 12,005
Limestone sales from Dakota Coal to Basin Electric	$ 3,552	$ 4,235
Water supply from Basin Electric to Dakota Gas	$ 2,727	$ 3,664
Natural gas sales from Dakota Gas to Basin Electric	$ 19,674	$ 15,140
Project services from Basin Electric to Dakota Gas	$ 345	$ 360

Various other intercompany management, administrative and financial services were performed, which were not significant.



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