BLACK HILLS CORP /SD/
Form 10-Q
August 07, 2018

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.

Commission File Number 001-31303

Black Hills Corporation
Incorporated in South Dakota IRS Identification Number 46-0458824
7001 Mount Rushmore Road
Rapid City, South Dakota 57702
Registrant's telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes x No o

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	(Do not check if a smaller reporting company)
	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section

13(a) of the Exchange Act. o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No x

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at July 31, 2018
Common stock, $1.00 par value	53,594,876 shares

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., a direct, wholly-owned subsidiary of Black Hills Gas Inc.
ASC	Accounting Standards Codification
ASU	Accounting Standards Update issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
Bbl	Barrel
BHC	Black Hills Corporation; the Company
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
CAPP	Customer Appliance Protection Plan
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
CIAC	Contribution In Aid of Construction
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
CDD	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPCN	Certificate of Public Convenience and Necessity
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission

CVA	Credit Valuation Adjustment
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)

Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
HDD	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
Horizon Point	Corporate headquarters building in Rapid City, South Dakota, which was completed in 2017.
IPP	Independent power producer
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
LIBOR	London Interbank Offered Rate
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MWh	Megawatt-hours
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
OCA	Office of Consumer Advocate
Peak View Wind Project	$109 million 60 MW wind generating project for Colorado Electric, adjacent to Busch Ranch wind farm
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended and restated on July 30, 2018 and now terminates on July 30, 2023.
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015
SEC	U. S. Securities and Exchange Commission
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
S&P	Standard and Poor's, a division of The McGraw-Hill Companies, Inc.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming and Montana
SSIR	System Safety and Integrity Rider
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
VIE	Variable interest entity
WPSC	Wyoming Public Service Commission
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by Pacificorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.

Wyoming Electric	Includes Cheyenne Light’s electric utility operations

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands, except per share amounts)			
Revenue	$355,704	$341,829	$931,093	$889,357
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	104,661	98,164	352,300	317,941
Operations and maintenance	118,282	111,897	234,378	226,449
Depreciation, depletion and amortization	48,709	46,825	97,299	93,527
Taxes - property, production and severance	13,976	13,072	27,276	26,458
Other operating expenses	525	2,075	2,015	5,000
Total operating expenses	286,153	272,033	713,268	669,375
Operating income	69,551	69,796	217,825	219,982
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(35,425)	(35,072)	(70,880)	(70,130)
Allowance for funds used during construction - borrowed	511	822	644	1,308
Capitalized interest	60	58	77	133
Interest income	320	257	630	298
Allowance for funds used during construction - equity	242	794	310	1,286
Other income (expense), net	(1,551)	(76)	(1,723)	(195)
Total other income (expense), net	(35,843)	(33,217)	(70,942)	(67,300)
Income before income taxes	33,708	36,579	146,883	152,682
Income tax benefit (expense)	(6,541)	(10,652)	19,261	(45,040)
Income from continuing operations	27,167	25,927	166,144	107,642
(Loss) from discontinued operations, net of tax	(2,427)	(616)	(4,770)	(2,185)
Net income	24,740	25,311	161,374	105,457
Net income attributable to noncontrolling interest	(2,823)	(3,116)	(6,453)	(6,739)
Net income available for common stock	$21,917	$22,195	$154,921	$98,718
Amounts attributable to common shareholders:				
Net income from continuing operations	$24,344	$22,811	$159,691	$100,903
Net (loss) from discontinued operations	(2,427)	(616)	(4,770)	(2,185)
Net income available for common stock	$21,917	$22,195	$154,921	$98,718
Earnings per share of common stock:				
Earnings (loss) per share, Basic -				
Income from continuing operations, per share	$0.46	$0.43	$2.99	$1.90
(Loss) from discontinued operations, per share	(0.05)	(0.01)	(0.09)	(0.04)

Earnings per share, Basic	$0.41	$0.42	$2.90	$1.86
Earnings (loss) per share, Diluted -				
Income from continuing operations, per share	$0.45	$0.41	$2.94	$1.83
(Loss) from discontinued operations, per share	(0.05)	(0.01)	(0.09)	(0.04)
Earnings per share, Diluted	$0.40	$0.40	$2.85	$1.79
Weighted average common shares outstanding:				
Basic	53,355	53,229	53,337	53,191
Diluted	54,520	55,384	54,361	55,179
Dividends declared per share of common stock	$0.475	$0.445	$0.950	$0.890

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Net income	$24,740	$25,311	$161,374	$105,457
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $9 and $18 for the three months ended June 30, 2018 and 2017 and $19 and $35 for the six months ended June 30, 2018 and 2017, respectively)	(35)	(31)	(70)	(62)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(135) and $(146) for the three months ended June 30, 2018 and 2017 and $(271) and $(300) for the six months ended June 30, 2018 and 2017, respectively)	487	268	973	528
Derivative instruments designated as cash flow hedges:				
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax (expense) benefit of $(152) and $(249) for the three months ended June 30, 2018 and 2017 and $(304) and $(530) for the six months ended June 30, 2018 and 2017, respectively)	561	464	1,122	985
Net unrealized gains (losses) on commodity derivatives (net of tax (expense) benefit of $(18) and $(194) for the three months ended June 30, 2018 and 2017 and $51 and $(536) for the six months ended June 30, 2018 and 2017, respectively)	30	331	(198)	915
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax (expense) benefit of $(45) and $143 for the three months ended June 30, 2018 and 2017 and $(190) and $249 for the six months ended June 30, 2018 and 2017, respectively)	118	(243)	594	(424)
Other comprehensive income, net of tax	1,161	789	2,421	1,942
Comprehensive income	25,901	26,100	163,795	107,399
Less: comprehensive income attributable to noncontrolling interest	(2,823)	(3,116)	(6,453)	(6,739)
Comprehensive income available for common stock	$23,078	$22,984	$157,342	$100,660

See Note 14 for additional disclosures.

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of June 30, 2018	December 31, 2017	June 30, 2017
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$8,630	$15,420	$11,528
Restricted cash	3,084	2,820	2,534
Accounts receivable, net	175,612	248,330	166,760
Materials, supplies and fuel	95,454	113,283	95,488
Derivative assets, current	666	304	639
Income tax receivable, net	11,653	—	—
Regulatory assets, current	50,565	81,016	53,061
Other current assets	31,431	25,367	20,768
Current assets held for sale	3,557	84,242	8,478
Total current assets	380,652	570,782	359,256
Investments	41,148	13,090	12,761
Property, plant and equipment	5,702,065	5,567,518	5,423,160
Less: accumulated depreciation and depletion	(1,087,689)	(1,026,088)	(964,549)
Total property, plant and equipment, net	4,614,376	4,541,430	4,458,611
Other assets:			
Goodwill	1,299,454	1,299,454	1,299,454
Intangible assets, net	7,155	7,559	7,972
Regulatory assets, non-current	210,137	216,438	244,099
Other assets, non-current	17,207	10,149	13,594
Noncurrent assets held for sale	—	—	113,999
Total other assets, non-current	1,533,953	1,533,600	1,679,118
TOTAL ASSETS	$6,570,129	$6,658,902	$6,509,746

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Continued)
(unaudited)

	As of June 30, 2018	December 31, 2017	June 30, 2017
	(in thousands, except share amounts)		
LIABILITIES AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$104,718	$160,887	$99,296
Accrued liabilities	190,339	219,462	191,806
Derivative liabilities, current	485	2,081	676
Accrued income taxes, net	—	1,022	5,160
Regulatory liabilities, current	52,102	6,832	17,305
Notes payable	121,800	211,300	107,975
Current maturities of long-term debt	255,743	5,743	5,743
Current liabilities held for sale	5,448	41,774	10,904
Total current liabilities	730,635	649,101	438,865
Long-term debt	2,858,068	3,109,400	3,160,302
Deferred credits and other liabilities:			
Deferred income tax liabilities, net	289,814	336,520	609,843
Regulatory liabilities, non-current	497,929	478,294	199,005
Benefit plan liabilities	162,199	159,646	176,102
Other deferred credits and other liabilities	104,951	105,735	112,550
Non-current liabilities held for sale	—	—	23,048
Total deferred credits and other liabilities	1,054,893	1,080,195	1,120,548
Commitments and contingencies (See Notes 9, 11, 16, 17)			
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,661,850; 53,579,986; and 53,513,521 shares, respectively	53,662	53,580	53,514
Additional paid-in capital	1,154,947	1,150,285	1,145,493
Retained earnings	652,642	548,617	512,498
Treasury stock, at cost – 64,981; 39,064; and 39,329 shares, respectively	(3,642)	(2,306)	(2,325)
Accumulated other comprehensive income (loss)	(38,763)	(41,202)	(32,941)
Total stockholders' equity	1,818,846	1,708,974	1,676,239
Noncontrolling interest	107,687	111,232	113,792
Total equity	1,926,533	1,820,206	1,790,031
TOTAL LIABILITIES AND TOTAL EQUITY	$6,570,129	$6,658,902	$6,509,746

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Six Months Ended June 30,	
	2018	2017
Operating activities:	(in thousands)	
Net income	$161,374	$105,457
Loss from discontinued operations, net of tax	4,770	2,185
Income from continuing operations	166,144	107,642
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	97,299	93,527
Deferred financing cost amortization	3,694	4,138
Stock compensation	5,221	6,589
Deferred income taxes	(21,419)	52,385
Employee benefit plans	6,911	5,717
Other adjustments, net	4,884	(6,445)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	18,492	7,753
Accounts receivable, unbilled revenues and other operating assets	50,711	94,591
Accounts payable and other operating liabilities	(96,394)	(117,134)
Regulatory assets - current	55,637	3,086
Regulatory liabilities - current	19,990	5,908
Other operating activities, net	(1,372)	(125)
Net cash provided by operating activities of continuing operations	309,798	257,632
Net cash provided by operating activities of discontinued operations	903	5,237
Net cash provided by operating activities	310,701	262,869
Investing activities:		
Property, plant and equipment additions	(156,748)	(154,294)
Purchase of investment	(24,429)	—
Other investing activities	(373)	238
Net cash provided by (used in) investing activities of continuing operations	(181,550)	(154,056)
Net cash provided by (used in) investing activities of discontinued operations	18,024	(9,474)
Net cash provided by (used in) investing activities	(163,526)	(163,530)
Financing activities:		
Dividends paid on common stock	(50,879)	(47,544)
Common stock issued	1,074	2,965
Net (payments) borrowings of short-term debt	(89,500)	11,375
Long-term debt - repayments	(2,871)	(52,871)
Distributions to noncontrolling interest	(9,998)	(8,335)
Other financing activities	(1,527)	(6,659)
Net cash provided by (used in) financing activities	(153,701)	(101,069)
Net change in cash, cash equivalents and restricted cash	(6,526)	(1,730)
Cash, cash equivalents and restricted cash at beginning of period	18,240	15,792
Cash, cash equivalents and restricted cash at end of period	$11,714	$14,062

See Note 15 for supplemental disclosure of cash flow information.

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of these Condensed Consolidated Financial Statements.

BLACK HILLS CORPORATION

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's 2017 Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The unaudited Condensed Consolidated Financial Statements included herein have been prepared by Black Hills Corporation (together with our subsidiaries the "Company," "us," "we," or "our"), pursuant to the rules and regulations of the SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations; however, we believe that the footnotes adequately disclose the information presented. These Condensed Consolidated Financial Statements should be read in conjunction with the consolidated financial statements and the notes thereto included in our 2017 Annual Report on Form 10-K filed with the SEC.

Segment Reporting

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. The Oil and Gas segment assets and liabilities are classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, excluding certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As of June 30, 2018, we have sold nearly all oil and gas assets. Transaction closing for the last few assets and final accounting are expected within the third quarter. The closing of the oil and gas office will occur in August. See Note 18 for more information on discontinued operations.

Use of Estimates and Basis of Presentation

The information furnished in the accompanying Condensed Consolidated Financial Statements reflects certain estimates required and all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2018, December 31, 2017, and June 30, 2017 financial information and are of a normal recurring nature. Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2018 and June 30, 2017, and our financial condition as of June 30, 2018, December 31, 2017, and June 30, 2017, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

Cash and Cash Equivalents and Restricted Cash

For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash equivalents.

Investments

We account for investments that we do not control under the cost method of accounting as we do not have the ability to exercise significant influence over the operating and financial policies of the investee. The cost method investments are recorded at cost and we record dividend income when applicable dividends are declared.

Recently Issued Accounting Standards

Leases, ASU 2016-02

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which supersedes ASC 840, Leases. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases, whereas today only financing-type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Under the current guidance, lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard. The FASB also issued additional amendments to the new lease standard in July 2018, ASU No. 2018-11, allowing companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported.

We expect to adopt this standard on January 1, 2019. For existing or expired land easements that were not previously accounted for as a lease, we anticipate electing the practical expedient which provides for no assessment of these easements. Further, we anticipate adopting the new standard with a cumulative effect adjustment with prior year comparative financial information remaining as previously reported when transitioning to the new standard. The standard also provides a transition practical expedient, commonly referred to as the "package of three", that must be taken together and allows entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. We expect to elect the "package of three" practical expedient. We continue to evaluate the additional transition practical expedients available under the guidance and the impact of this new standard on our financial position, results of operations and cash flows. We are finalizing the process of identifying and categorizing our lease contracts and evaluating our current business processes relating to leases. We have selected and configured a new lease software solution that we are currently testing. We also continue to monitor utility industry lease implementation guidance that may change existing and future lease classification.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities, ASU 2017-12

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. This ASU is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We do not anticipate the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

Simplifying the Test for Goodwill Impairment, ASU 2017-04

In January 2017, the FASB issued ASU 2017-04, Simplifying the Test for Goodwill Impairment (Topic 350) by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this standard to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

Effective January 1, 2018, we adopted ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and its related amendments (collectively known as ASC 606). Under this standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. We applied the five-step method outlined in the ASU to all in-scope revenue streams and elected the modified retrospective implementation method. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows. Implementation of the standard did not have a significant impact on the measurement or recognition of revenue; therefore, no cumulative adoption adjustment to the opening balance of Retained earnings at the date of initial application was necessary. The additional disclosures required by the ASU are included in Note 2.

Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, ASU 2017-07

Effective January 1, 2018, we adopted ASU 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost. The standard requires employers to report the service cost component in the same line item(s) as other compensation costs, and require the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets was applied on a prospective basis for the six months ended June 30, 2018. Retrospective impact was not material and therefore prior year presentation was not changed. For our rate-regulated entities, we capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities and maintain a FERC-to-GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs resulted in offsetting changes to Operating income and Other income. Implementation of the standard did not have a material impact on our financial position, results of operations or cash flows.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

Effective January 1, 2018, we adopted ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). This ASU requires changes in the presentation of certain items, including but not limited to, debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. We implemented this standard effective January 1, 2018 using the retrospective transition method. This standard had no impact on our financial position, results of operations or cash flows.

Statement of Cash Flows: Restricted Cash, ASU 2016-18

Effective January 1, 2018, we adopted ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This ASU provides guidance on the presentation of restricted cash or restricted cash equivalents and reduces the diversity in practice. This ASU requires amounts generally described as restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling beginning-of-period and end-of-period total amounts on the statement of cash flows. We elected, as permitted by the standard, to early adopt ASU 2016-18 retrospectively as of January 1, 2017 and have applied it to all periods presented herein. The adoption of ASU 2016-18 did not have a material impact to our condensed consolidated financial statements. The effect of the adoption of ASU 2016-18 on our Condensed Consolidated Statements of Cash Flows was to include restricted cash balances in the beginning and end of period balances of cash, cash equivalents, and restricted cash. The change in restricted cash was previously disclosed in investing activities in the Condensed Consolidated Statements of Cash Flows.

(2) REVENUE

Revenue Recognition

Revenues are recognized in an amount that reflects the consideration we expect to receive in exchange for goods or services, when control of the promised goods or services is transferred to our customers. Our primary types of revenue contracts are:

- Regulated natural gas and electric utility services tariffs - Our utilities have regulated operations, as defined by ASC 980, that provide services to regulated customers under rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Collectively, these rates, charges, terms and conditions are included in a tariff, which governs all aspects of the provision of our regulated services. Our regulated services primarily encompass single performance obligations material to the context of the contract for delivery of either commodity natural gas, commodity electricity, natural gas transportation or electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the regulator-empowered statute to establish contractual rates between the utility and its customers. All of our utilities' regulated sales are subject to regulatory-approved tariffs.

- Power sales agreements - Our electric utilities and power generation segments have long-term wholesale power sales agreements with other load-serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of "take or pay" arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, Black Hills also sells excess energy to other load-serving entities on a short-term basis as a member of the Western States Power Pool. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price and is variable based on energy delivered.

- Coal supply agreements - Our mining segment sells coal primarily under long-term contracts to utilities for use at their power generating plants, including affiliate electric utilities, and an affiliate non-regulated power generation entity. The contracts include a single promise to supply coal necessary to fuel the customers' facilities during the contract term. The transaction price is established in the coal supply agreements, including cost-based agreements with the affiliated regulated utilities, and is variable based on tons of coal delivered.

- Other non-regulated services - Our natural gas and electric utility segments also provide non-regulated services primarily comprised of appliance repair service and protection plans, electric and natural gas technical infrastructure construction and maintenance services, and in Nebraska and Wyoming, an unbundled natural gas commodity offering under the regulatory-approved Choice Gas Program. Revenue contracts for these services generally represent a single performance obligation with the price reflecting the standalone selling price stated in the agreement, and the revenue is variable based on the units delivered or services provided.

The following tables depict the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition for each of the reporting segments, for the three and six months ended June 30, 2018. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended June 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:	(in thousands)					
Retail	$145,377	$135,863	$ —	$16,345	$ (7,979)	$289,606
Transportation	—	29,011	—	—	(301)	28,710
Wholesale	8,191	—	12,743	—	(11,613)	9,321
Market - off-system sales	4,938	162	—	—	(1,660)	3,440
Transmission/Other	13,356	11,672	—	—	(3,644)	21,384
Revenue from contracts with customers	171,862	176,708	12,743	16,345	(25,197)	352,461
Other revenues	1,754	912	9,141	554	(9,118)	3,243
Total revenues	$173,616	$177,620	$ 21,884	$16,899	$ (34,315)	$355,704
Timing of revenue recognition:						
Services transferred at a point in time	$—	$—	$ —	$16,345	$ (7,978)	$8,367
Services transferred over time	171,862	176,708	12,743	—	(17,219)	344,094
Revenue from contracts with customers	$171,862	$176,708	$ 12,743	$16,345	$ (25,197)	$352,461

Six Months Ended June 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:	(in thousands)					
Retail	$292,434	$477,257	$ —	$32,902	$ (15,821)	$786,772
Transportation	—	70,681	—	—	(710)	69,971
Wholesale	17,241	—	26,676	—	(23,826)	20,091
Market - off-system sales	9,082	589	—	—	(4,182)	5,489
Transmission/Other	26,427	24,341	—	—	(7,275)	43,493
Revenue from contracts with customers	345,184	572,868	26,676	32,902	(51,814)	925,816
Other revenues	1,987	2,096	18,311	1,125	(18,242)	5,277
Total revenues	$347,171	$574,964	$ 44,987	$34,027	$ (70,056)	$931,093
Timing of revenue recognition:						
Services transferred at a point in time	$—	$—	$ —	$32,902	$ (15,820)	$17,082
Services transferred over time	345,184	572,868	26,676	—	(35,994)	908,734
Revenue from contracts with customers	$345,184	$572,868	$ 26,676	$32,902	$ (51,814)	$925,816

The majority of our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our consolidated revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

Revenue Not in Scope of ASC 606
Other revenues included in the tables above include our revenue accounted for under separate accounting guidance, including lease revenue under ASC 840 and alternative revenue programs revenue under ASC 980. The majority of our lease revenue is related to a 20-year power sale agreement between Colorado IPP and affiliate Colorado Electric. This agreement is accounted for as a direct financing lease whereby Colorado IPP receives revenue for energy delivered and related capacity payments. This lease revenue is eliminated in our consolidated revenues.

Significant Judgments and Estimates
TCJA Revenue Reserve

The TCJA or “tax reform” signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We estimated and recorded a reserve to revenue of approximately $8.0 million and $23 million during the three and six months ended June 30, 2018, respectively. As of June 30, 2018, $3.3 million has been returned to customers and approximately $19 million remains in reserve.

Unbilled Revenue

Revenues attributable to natural gas and electricity delivered to customers but not yet billed are estimated and accrued, and the related costs are charged to expense. Factors influencing the determination of unbilled revenues include estimates of delivered sales volumes based on weather information and customer consumption trends.

Contract Balances

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable further discussed in Note 4. We do not typically incur costs that would be capitalized to obtain or fulfill a contract.

Practical Expedients
Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer, and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice.

We have revenue contract performance obligations with similar characteristics, and we reasonably expect that the financial statement impact of applying the new revenue recognition guidance to a portfolio of contracts would not differ materially from applying this guidance to the individual contracts or performance obligations within the portfolio. Therefore, we have elected the portfolio approach in applying the new revenue guidance.

(3) BUSINESS SEGMENT INFORMATION

Segment information and Corporate and Other included in the accompanying Condensed Consolidated Statements of Income were as follows (in thousands):

Three Months Ended June 30, 2018	External Operating Revenue		Inter-company Operating Revenue		Total Revenues	Net income (loss) from continuing operations
	Contract Customers	Other Revenues	Contract Customers	Other Revenues		
Segment:						
Electric	$ 166,565	$ 1,754	$ 5,297	$ —	$ 173,616	$ 21,890
Gas	176,399	912	309	—	177,620	(1,161)
Power Generation (b)	1,130	348	11,613	8,793	21,884	4,772
Mining	8,367	229	7,978	325	16,899	3,005
Corporate and Other	—	—	—	—	—	(4,162)
Inter-company eliminations	—	—	(25,197)	(9,118)	(34,315)	—
Total	$ 352,461	$ 3,243	$ —	$ —	$ 355,704	$ 24,344

Under our modified retrospective adoption of ASU 2014-09, revenues for the three and six months ended June 30, 2017 are not presented by contract type.

Three Months Ended June 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric	$ 165,517	$ 2,936	$ 18,832
Gas	166,439	8	(272)
Power Generation (b)	1,470	20,325	5,332
Mining	8,403	6,543	2,681
Corporate and Other	—	—	(3,762)
Inter-company eliminations	—	(29,812)	—
Total	$ 341,829	$ —	$ 22,811

Six Months Ended June 30, 2018	External Operating Revenue		Inter-company Operating Revenue		Total Revenues	Net income (loss) from continuing operations
	Contract Customers	Other Revenues	Contract Customers	Other Revenues		
Segment:						
Electric	$ 333,743	$ 1,987	$ 11,441	$ —	$ 347,171	$ 41,735
Gas (a)	572,141	2,096	727	—	574,964	106,459
Power Generation (b)	2,850	718	23,826	17,593	44,987	10,628
Mining	17,082	476	15,820	649	34,027	5,989
Corporate and Other	—	—	—	—	—	(5,120)
Inter-company eliminations	—	—	(51,814)	(18,242)	(70,056)	—
Total	$ 925,816	$ 5,277	$ —	$ —	$ 931,093	$ 159,691

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Six Months Ended June 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric	$ 337,687	$ 6,790	$ 41,062
Gas	531,340	17	45,738
Power Generation (b)	3,572	41,790	11,862
Mining	16,758	14,734	5,571
Corporate and Other (c)	—	—	(3,330)
Inter-company eliminations	—	(63,331)	—
Total	$ 889,357	$ —	$ 100,903

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(a) Net income from continuing operations available for common stock for the six months ended June 30, 2018 included a $49 million tax benefit resulting from legal entity restructuring. See Note 19 Income Taxes of the Notes to Condensed Consolidated Financial Statements for more information.

(b) Net income from continuing operations available for common stock for the three and six months ended June 30, 2018 and June 30, 2017 reflects net income attributable to noncontrolling interests of $2.8 million and $6.5 million, and $3.1 million and $6.6 million, respectively.

(c) Net income (loss) from continuing operations available for common stock for the six months ended June 30, 2017 included a $1.4 million tax benefit recognized from carryback claims for specified liability losses involving prior tax years.

Segment information and Corporate balances included in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

Total Assets (net of inter-company eliminations) as of:	June 30, 2018	December 31, 2017	June 30, 2017
Segment:			
Electric (a)	$2,902,925	$2,906,275	$2,901,570
Gas	3,367,247	3,426,466	3,242,461
Power Generation (a)	49,628	60,852	66,292
Mining	68,154	65,455	67,365
Corporate and Other	178,618	115,612	109,581
Discontinued operations	3,557	84,242	122,477
Total assets	$6,570,129	$6,658,902	$6,509,746

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(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation Station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

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(4) ACCOUNTS RECEIVABLE

Following is a summary of Accounts receivable, net included in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

June 30, 2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 44,577	$ 34,940	$ (503)	$ 79,014
Gas Utilities	70,244	23,557	(3,517)	90,284
Power Generation	1,681	—	—	1,681
Mining	3,158	—	—	3,158
Corporate	1,475	—	—	1,475
Total	$ 121,135	$ 58,497	$ (4,020)	$ 175,612

December 31, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,347	$ 36,384	$ (586)	$ 75,145
Gas Utilities	81,256	88,967	(2,495)	167,728
Power Generation	1,196	—	—	1,196
Mining	2,804	—	—	2,804
Corporate	1,457	—	—	1,457
Total	$ 126,060	$ 125,351	$ (3,081)	$ 248,330

June 30, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,635	$ 33,686	$ (466)	$ 74,855
Gas Utilities	62,908	26,584	(2,535)	86,957
Power Generation	877	—	—	877
Mining	2,904	—	—	2,904
Corporate	1,167	—	—	1,167
Total	$ 109,491	$ 60,270	$ (3,001)	$ 166,760

(5) REGULATORY ACCOUNTING

We had the following regulatory assets and liabilities (in thousands) as of:

	Maximum Amortization (in years)	June 30, 2018	December 31, 2017	June 30, 2017
Regulatory assets				
Deferred energy and fuel cost adjustments [(a)]	1	$26,725	$20,187	$20,761
Deferred gas cost adjustments [(a)]	1	962	31,844	8,962
Gas price derivatives [(a)]	3	9,120	11,935	11,159
Deferred taxes on AFUDC [(b) (f)]	45	7,813	7,847	15,322
Employee benefit plans [(c)]	12	108,366	109,235	107,419
Environmental [(a)]	subject to approval	1,000	1,031	1,070
Asset retirement obligations [(a)]	44	523	517	510
Loss on reacquired debt [(a)]	28	19,868	20,667	21,466
Renewable energy standard adjustment [(a)]	subject to approval	1,179	1,088	768
Deferred taxes on flow through accounting [(c) (f)]	54	28,193	26,978	40,586
Decommissioning costs	10	11,806	13,287	14,681
Gas supply contract termination [(a)]	4	17,171	20,001	22,793
Other regulatory assets [(a)]	30	27,976	32,837	31,663
Total regulatory assets		260,702	297,454	297,160
Less current regulatory assets		(50,565)	(81,016)	(53,061)
Regulatory assets, non-current		$210,137	$216,438	$244,099
Regulatory liabilities				
Deferred energy and gas costs [(a)]	1	$27,188	$3,427	$13,693
Employee benefit plan costs and related deferred taxes [(c) (f)]	12	39,820	40,629	67,297
Cost of removal [(a)]	44	141,954	130,932	125,598
Excess deferred income taxes [(c) (d)]	40	310,132	301,553	56
TCJA revenue reserve [(e)]	subject to approval	19,312	—	—
Other regulatory liabilities [(c)]	25	11,625	8,585	9,666
Total regulatory liabilities		550,031	485,126	216,310
Less current regulatory liabilities		(52,102)	(6,832)	(17,305)
Regulatory liabilities, non-current		$497,929	$478,294	$199,005

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(a) Recovery of costs, but we are not allowed a rate of return.

(b) In addition to recovery of costs, we are allowed a rate of return.

(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.

(d) The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate. As of June 30, 2018 and December 31, 2017, all of the liability was classified as non-current due to uncertainties around the timing and other regulatory decisions that will affect the amount of regulatory tax liability amortized and returned to customers through rate reductions of other revenue offsets in 2018.

(e) As of June 30, 2018, the amortization periods are yet to be determined and subject to approval by our regulators.

(f) The variance to the prior periods is primarily due to the TCJA.

Regulatory Matters

Except as discussed below, there have been no other significant changes to our Regulatory Matters from those previously disclosed in Note 13 of the Notes to the Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

TCJA revenue reserve - The TCJA signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21%. Effective January 1, 2018, the key impact of tax reform on existing utility revenues/tariffs established prior to tax reform results primarily from the change in the federal tax rate from 35% to 21% (including the effects of tax gross-ups not yet approved) affecting current income tax expense embedded in those tariffs. Black Hills has been collaborating with utility commissions in the states in which it provides utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We have now received state utility commission approvals to provide the benefits of federal tax reform to utility customers in four states. Discussions are underway with utility commissions in the remaining states and final approval is expected prior to year-end. We estimated and recorded a reserve to revenue of approximately $8.0 million and $23 million during the three and six months ended June 30, 2018, respectively. As of June 30, 2018, $3.3 million has been returned to customers.

A list of states where benefits to customers of federal tax reform have been approved is summarized below.

State	Approximate Annual Benefit for Customers		Start Date for Customer Benefits
Colorado	$10.8	million	July 2018
Iowa	$2.2	million	June 2018
Kansas	$1.9	million	April 2018
Nebraska	$3.8	million	July 2018

In support of returning benefits to customers, the three rate review requests filed in late 2017 for Arkansas Gas, Wyoming Gas (Northwest Wyoming) and Rocky Mountain Natural Gas (a pipeline system in Colorado) were adjusted to include the benefits to customers of federal tax reform as discussed below.

Rate Reviews - In Colorado, new rates for RMNG went into effect June 1, 2018 after an administrative law judge recommended approval of a settlement agreement and the CPUC took no further action. The settlement included $1.1 million in annual revenue increases and an extension of SSIR to recover costs from 2018 through December 31, 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt.

On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We expect the final order in the third quarter of 2018. The settlement provides for $1.0 million of new revenue, a return on equity of 9.6%, and a capital structure of 54.0% equity and 46.0% debt. New rates, inclusive of customer benefits related to the TCJA, will be effective September 1, 2018.

An Arkansas rate review was filed in December 2017 with the APSC requesting $30 million of annual revenue to recover more than $160 million of new infrastructure investment. The revenue request was subsequently adjusted to $19 million primarily related to a lower corporate income tax rate of 21%. The APSC previously issued a procedural schedule for the rate review. To date, testimony has been filed by the intervenors and Arkansas Gas filed rebuttal testimony on June 26, 2018. The APSC issued an order on July 26 requiring investor owned utilities to provide within 30 days their plans to return tax reform benefits to customers. Arkansas Gas is reviewing the order and its impacts to customers and may amend its current rate review if necessary. A final order and new rates are expected to be effective in the fourth quarter of 2018.

(6) MATERIALS, SUPPLIES AND FUEL

The following amounts by major classification are included in Materials, supplies and fuel in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2018	December 31, 2017	June 30, 2017
Materials and supplies	$73,075	$69,732	$68,759
Fuel - Electric Utilities	2,821	2,962	3,106
Natural gas in storage held for distribution	19,558	40,589	23,623
Total materials, supplies and fuel	$95,454	$113,283	$95,488

(7) INVESTMENTS

In February 2018, we contributed $28 million of assets in exchange for equity securities in a privately held company. The carrying value of our investment in the equity securities was determined using the cost method. We review this investment on a periodic basis to determine whether a significant event or change in circumstances has occurred that may have an adverse effect on the value of the investment. We estimate that the fair value of this cost method investment approximated or exceeded its carrying value as of June 30, 2018.

The following table presents the carrying value of our investments (in thousands) as of:

	June 30, 2018	December 31, 2017	June 30, 2017
Cost method investment	$28,134	$ —	$—
Cash surrender value of life insurance contracts	13,014	13,090	12,761
Total investments	$41,148	$ 13,090	$12,761

(8) EARNINGS PER SHARE

A reconciliation of share amounts used to compute Earnings (loss) per share in the accompanying Condensed Consolidated Statements of Income was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income available for common stock	$21,917	$22,195	$154,921	$98,718
Weighted average shares - basic	53,355	53,229	53,337	53,191
Dilutive effect of:				
Equity Units [(a)]	1,057	1,977	904	1,796
Equity compensation	108	178	120	192
Weighted average shares - diluted	54,520	55,384	54,361	55,179

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(a) Calculated using the treasury stock method.

The following outstanding securities were excluded in the computation of diluted net income (loss) per share as their inclusion would have been anti-dilutive (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Equity compensation	15	—	17	—
Anti-dilutive shares	15	—	17	—

(9) NOTES PAYABLE, CURRENT MATURITIES AND DEBT

We had the following notes payable outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2018		December 31, 2017		June 30, 2017	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$—	$11,448	$—	$26,848	$—	$24,540
CP Program	121,800	—	211,300	—	107,975	—
Total	$121,800	$11,448	$211,300	$26,848	$107,975	$24,540

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our Corporate credit rating from S&P, Fitch, and Moody's for our senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at June 30, 2018 and are unchanged under our amended and restated Revolving Credit Facility. Based on our credit ratings, a 0.200% commitment fee was charged on the unused amount at June 30, 2018. This commitment fee requirement is unchanged under our amended and restated Revolving Credit Facility.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net payments under the CP Program during the six months ended June 30, 2018 were $90 million and our notes outstanding as of June 30, 2018 were $122 million. As of June 30, 2018, the weighted average interest rate on CP Program borrowings was 2.29%.

Debt Covenants

Under our Revolving Credit Facility and term loan agreement (before each was amended and restated), we were required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. At June 30, 2018, our Consolidated Indebtedness to Capitalization Ratio was calculated by dividing (i) Consolidated Indebtedness (which included letters of credit and certain guarantees issued but excluded the RSNs), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excluded noncontrolling interests in subsidiaries and included the aggregate outstanding amount of the RSNs). Under our amended and restated revolving Credit Facility and amended and restated term loan agreement, we are also required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00, but as of September 30, 2018 only, Consolidated Net Worth will include the amount receivable by the Company in connection with the common stock settlement under the purchase contracts which are part of the Equity Units, rather than the outstanding amount of the RSNs.

Our Revolving Credit Facility and term loans require compliance with the following financial covenant at the end of each quarter:

	As of June 30, 2018	Covenant Requirement
Consolidated Indebtedness to Capitalization Ratio	58%	Less than 65%

As of June 30, 2018, we were in compliance with this covenant.

Current Maturities

As of June 30, 2018, our $250 million Senior unsecured notes due January 11, 2019 and $5.7 million of principal due in the next twelve months on our Corporate term loan due June 7, 2021 are classified as Current maturities of long-term debt on our Condensed Consolidated Balance Sheets.

Long-Term Debt

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at June 30, 2018, will now mature on July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. The interest cost associated with this term loan is determined based upon our corporate credit rating from S&P, Fitch, and Moody's for our Senior unsecured long-term debt. Based on our credit ratings, the margins for base rate borrowings and Eurodollar borrowings were 0.050% and 1.050%, respectively, at June 30, 2018, and are 0.000% and 0.750%, respectively, under our amended and restated Revolving Credit Facility.

(10) EQUITY

A summary of the changes in equity is as follows:

Six Months Ended June 30, 2018	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2017	$ 1,708,974	$ 111,232	$ 1,820,206
Net income (loss)	154,921	6,453	161,374
Other comprehensive income (loss)	2,421	—	2,421
Dividends on common stock	(50,879)	—	(50,879)
Share-based compensation	3,194	—	3,194
Dividend reinvestment and stock purchase plan	219	—	219
Other stock transactions	(4)	—	(4)
Distribution to noncontrolling interest	—	(9,998)	(9,998)
Balance at June 30, 2018	$ 1,818,846	$ 107,687	$ 1,926,533

Six Months Ended June 30, 2017	Total Stockholders' Equity	Noncontrolling Interest	Total Equity
		(in thousands)	
Balance at December 31, 2016	$ 1,614,639	$ 115,495	$ 1,730,134
Net income (loss)	98,718	6,632	105,350
Other comprehensive income (loss)	1,942	—	1,942
Dividends on common stock	(47,544)	—	(47,544)
Share-based compensation	4,133	—	4,133
Dividend reinvestment and stock purchase plan	1,530	—	1,530
Redeemable noncontrolling interest	(886)	—	(886)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(7)	—	(7)
Distribution to noncontrolling interest	—	(8,335)	(8,335)
Balance at June 30, 2017	$ 1,676,239	$ 113,792	$ 1,790,031

At-the-Market Equity Offering Program

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On August 4, 2017, we renewed our ATM equity offering program which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior program other than the aggregate value increased from $200 million to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares during the six months ended June 30, 2018 and June 30, 2017 under the ATM equity offering program.

Noncontrolling Interest

Colorado IPP owns a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Colorado IPP to a third-party buyer. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Colorado IPP. Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our Condensed Consolidated Balance Sheets related to the VIE described above as of:

	June 30, 2018	December 31, 2017	June 30, 2017
	(in thousands)		
Assets			
Current assets	$11,462	$14,837	$12,042
Property, plant and equipment of variable interest entities, net	$203,308	$208,595	$214,239
Liabilities			
Current liabilities	$2,946	$4,565	$2,651

(11) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operation of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures as discussed in our 2017 Annual Report on Form 10-K.

Market Risk

Market risk is the potential loss that might occur as a result of an adverse change in market price or rate. We are exposed to the following market risks including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain gas-fired generation assets; and

- Interest rate risk associated with our variable rate debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements, and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit, and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based on payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income and Condensed Consolidated Statements of Comprehensive Income are detailed below and in Note 12.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements), expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Condensed Consolidated Balance Sheets in accordance with state commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Condensed Consolidated Statements of Income.

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from July 2018 through May 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Fuel, purchased power and cost of natural gas sold in the accompanying Condensed Consolidated Statements of Income. Effectiveness of our hedging position is evaluated at inception of the hedge, upon occurrence of a triggering event and as of the end of each quarter.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our utilities are composed of both long and short positions. We were in a net long position as of:

	June 30, 2018		December 31, 2017		June 30, 2017	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	5,680,000	30	8,330,000	36	11,060,000	42
Natural gas options purchased, net	1,140,000	9	3,540,000	14	1,640,000	20

Natural gas basis swaps purchased	5,720,000	30	8,060,000	36	10,070,000	42
Natural gas over-the-counter swaps, net [(b)]	4,950,000	23	3,820,000	29	5,200,000	23
Natural gas physical contracts, net [(c)]	3,866,648	210	12,826,605	35	8,427,119	10

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(a) Term reflects the maximum forward period hedged.

(b) As of June 30, 2018, 2,452,000 MMBtus were designated as cash flow hedges for the natural gas over-the-counter swaps purchased.

(c) Volumes exclude contracts that qualify for the normal purchase, normal sales exception.

Based on June 30, 2018 prices, a $0.1 million loss would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

We have certain derivative contracts which contain credit provisions. These credit provisions may require the Company to post collateral when credit exposure to the Company is in excess of a negotiated line of unsecured credit. At June 30, 2018, the Company posted $0.7 million related to such provisions, which is included in Other current assets on the Condensed Consolidated Balance Sheets.

Financing Activities

At June 30, 2018, we had no outstanding interest rate swap agreements. Our last interest rate swap agreement with a $50 million notional value, which was designated to borrowings on our Revolving Credit Facility, expired in January 2017.

Discontinued Operations

Our Oil and Gas segment was exposed to risks associated with changes in the market prices of oil and gas. Through December 2017, we used exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production to mitigate commodity price risk and preserve cash flows. Hedge accounting was elected on the swaps and futures contracts. These transactions were designated upon inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. As a result of divesting our Oil and Gas assets, these activities were discontinued and there were no outstanding derivative agreements as of June 30, 2018 or December 31, 2017. At June 30, 2017, we had outstanding crude oil futures and swap contracts with notional volumes of 72,000 Bbls, crude oil option contracts with notional volumes of 18,000 Bbls and natural gas futures and swap contracts with notional volumes of 1,080,000 MMBtus.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three and six months ended June 30, 2018 and 2017 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

Three Months Ended June 30, 2018

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (713)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(163)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (876)		$ —

Three Months Ended June 30, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (713)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	430	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(44)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (327)		$ —

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Six Months Ended June 30, 2018

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (1,426)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(784)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (2,210)		$ —

Six Months Ended June 30, 2017

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (1,515)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	659	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	14	Fuel, purchased power and cost of natural gas sold	—
Total		$ (842)		$ —

The following tables summarize the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the three and six months ended June 30, 2018 and 2017. The amounts included in the tables below exclude gains and losses arising from ineffectiveness because these amounts, if any, are immediately recognized in the Condensed Consolidated Statements of Income as incurred.

	Three Months Ended June 30, 2018	2017
	(in thousands)	
Increase (decrease) in fair value:		

Forward commodity contracts	$48	$525
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	713	713
Forward commodity contracts	163	(386)
Total other comprehensive income (loss) from hedging	$924	$852

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Increase (decrease) in fair value:		
Forward commodity contracts	$(249)	$1,451
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	1,426	1,515
Forward commodity contracts	784	(673)
Total other comprehensive income (loss) from hedging	$1,961	$2,293

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Condensed Consolidated Statements of Income for the three and six months ended June 30, 2018 and 2017 (in thousands). Note that this presentation does not reflect gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic profit or loss we realized when the underlying physical and financial transactions were settled.

		Three Months Ended June 30,	
		2018	2017
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Net (loss) from discontinued operations	$—	$ 26
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	771	(691)
		$771	$ (665)

		Six Months Ended June 30,	
		2018	2017
Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income	Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Net (loss) from discontinued operations	$—	$ 143
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	1,025	(1,500)
		$1,025	$ (1,357)

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our utilities were $9.1 million, $12 million and $11 million at June 30, 2018, December 31, 2017 and June 30, 2017, respectively.

(12) FAIR VALUE MEASUREMENTS

Derivative Financial Instruments

The accounting guidance for fair value measurements requires certain disclosures about assets and liabilities measured at fair value. This guidance establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments. For additional information, see

Notes 1, 9, 10 and 11 to the Consolidated Financial Statements included in our 2017 Annual Report on Form 10-K filed with the SEC.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Discontinued Operations:

- Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 18.

Utilities Segments:

- The commodity contracts for our Utilities Segments, are valued using the market approach and include exchange-traded futures, options, basis swaps and over-the-counter swaps and options (Level 2) for natural gas contracts. For exchange-traded futures, options and basis swap assets and liabilities, fair value was derived using broker quotes validated by the exchange settlement pricing for the applicable contract. For over-the-counter instruments, the fair value is obtained by utilizing a nationally recognized service that obtains observable inputs to compute the fair value, which we validate by comparing our valuation with the counterparty. The fair value of these swaps includes a CVA component based on the credit spreads of the counterparties when we are in an unrealized gain position or on our own credit spread when we are in an unrealized loss position.

Corporate Activities:

- As of June 30, 2018, we no longer have derivatives within our corporate activities as our last interest rate swaps matured in January 2017.

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 18. The following tables set forth by level within the fair value hierarchy present gross assets and gross liabilities and related offsetting cash collateral and counterparty netting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments.

	As of June 30, 2018				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total

	(in thousands)			
Assets:				
Commodity derivatives — Utilities	$ $1,035	$ —	$ (363)	$ 672
Total	$ $1,035	$ —	$ (363)	$ 672
Liabilities:				
Commodity derivatives — Utilities	$ $9,808	$ —	$ (9,144)	$ 664
Total	$ $9,808	$ —	$ (9,144)	$ 664

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	As of December 31, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Total	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259
Total	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259

	As of June 30, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 1,622	$ —	$ (977)	$ 645
Total	$ —	$ 1,622	$ —	$ (977)	$ 645
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 12,331	$ —	$ (11,568)	$ 763
Total	$ —	$ 12,331	$ —	$ (11,568)	$ 763

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

The following tables present the fair value and balance sheet classification of our derivative instruments (in thousands):
As of June 30, 2018

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 128	$ —
Commodity derivatives	Other assets, non-current	6	—
Commodity derivatives	Derivative liabilities — current	—	305
Commodity derivatives	Other deferred credits and other liabilities	—	16
Total derivatives designated as hedges		$ 134	$ 321

Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 538	$ —
Commodity derivatives	Other assets, non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	180
Commodity derivatives	Other deferred credits and other liabilities	—	163
Total derivatives not designated as hedges		$ 538	$ 343

As of December 31, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative liabilities — current	$ —	$ 817
Commodity derivatives	Other deferred credits and other liabilities	—	67
Total derivatives designated as hedges		$ —	$ 884
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 304	$ —
Commodity derivatives	Derivative liabilities — current	—	1,264
Commodity derivatives	Other deferred credits and other liabilities	—	111
Total derivatives not designated as hedges		$ 304	$ 1,375

As of June 30, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 39	$ —
Commodity derivatives	Current assets held for sale	509	—
Commodity derivatives	Noncurrent assets held for sale	31	—
Commodity derivatives	Derivative liabilities — current	—	140
Commodity derivatives	Other deferred credits and other liabilities	—	32
Commodity derivatives	Current liabilities held for sale	—	27
Total derivatives designated as hedges		$ 579	$ 199
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 600	$ —
Commodity derivatives	Other assets, non-current	6	—
Commodity derivatives	Derivative liabilities — current	—	536
Commodity derivatives	Other deferred credits and other liabilities	—	55
Commodity derivatives	Current liabilities held for sale	—	17
Total derivatives not designated as hedges		$ 606	$ 608

Fair value measurements also apply to the valuation of our pension and postretirement plan assets. Current accounting guidance requires employers to annually disclose information about the fair value measurements of their assets of a defined benefit pension or other postretirement plan. The fair value of these assets is presented in Note 18 to the Consolidated Financial Statements included in our 2017 Annual Report on Form 10-K.

(13) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 12, were as follows (in thousands) as of:

	June 30, 2018		December 31, 2017		June 30, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [a]	$8,630	$8,630	$15,420	$15,420	$11,528	$11,528
Restricted cash [a]	$3,084	$3,084	$2,820	$2,820	$2,534	$2,534
Notes payable [b]	$121,800	$121,800	$211,300	$211,300	$107,975	$107,975
Long-term debt, including current maturities [c] [d]	$3,113,811	$3,234,780	$3,115,143	$3,350,544	$3,166,045	$3,377,891

(a) Carrying value approximates fair value due to either the short-term length of maturity or variable interest rates that approximate prevailing market rates, and therefore is classified in Level 1 in the fair value hierarchy.

(b) Notes payable consist of commercial paper borrowings and borrowings on our Revolving Credit Facility. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.

(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

(d) Carrying amount of long-term debt is net of deferred financing costs.

(14) OTHER COMPREHENSIVE INCOME (LOSS)

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Condensed Consolidated Statements of Income for the period, net of tax (in thousands):

	Location on the Condensed Consolidated Statements of Income	Amount Reclassified from AOCI Three Months Ended June 30, 2018	June 30, 2017	Six Months Ended June 30, 2018	June 30, 2017
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$(713)	$(713)	$(1,426)	$(1,515)
Commodity contracts	Net (loss) from discontinued operations	—	430	—	659
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(163)	(44)	(784)	14
		(876)	(327)	(2,210)	(842)
Income tax	Income tax benefit (expense)	197	106	494	281
Total reclassification adjustments related to cash flow hedges, net of tax		$(679)	$(221)	$(1,716)	$(561)
Amortization of components of defined benefit plans:					
Prior service cost	Operations and maintenance	$44	$49	$89	$97
Actuarial gain (loss)	Operations and maintenance	(622)	(414)	(1,244)	(828)
		(578)	(365)	(1,155)	(731)
Income tax	Income tax benefit (expense)	126	128	252	265
Total reclassification adjustments related to defined benefit plans, net of tax		$(452)	$(237)	$(903)	$(466)
Total reclassifications		$(1,131)	$(458)	$(2,619)	$(1,027)

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Balances by classification included within AOCI, net of tax on the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2017	$(19,581)	$ (518)	$(21,103)	$(41,202)
Other comprehensive income (loss) before reclassifications	—	(198)	—	(198)
Amounts reclassified from AOCI	1,122	594	903	2,619
Reclassifications of certain tax effects from AOCI	15	—	3	18
Ending Balance June 30, 2018	$(18,444)	$ (122)	$(20,197)	$(38,763)

	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
Balance as of December 31, 2016	$(18,109)	$ (233)	$(16,541)	$(34,883)
Other comprehensive income (loss) before reclassifications	—	915	—	915
Amounts reclassified from AOCI	985	(424)	466	1,027
Ending Balance June 30, 2017	$(17,124)	$ 258	$(16,075)	$(32,941)

(15) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six Months Ended	June 30, 2018	June 30, 2017
	(in thousands)	
Non-cash investing and financing activities —		
Property, plant and equipment acquired with accrued liabilities	$37,168	$31,579
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$(67,119)	$(65,820)
Income taxes (paid) refunded	$(14,837)	$1

(16) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The components of net periodic benefit cost for the Defined Benefit Pension Plan were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Service cost	$1,709	$1,759	$3,417	$3,517
Interest cost	3,868	3,880	7,735	7,760
Expected return on plan assets	(6,185)	(6,129)	(12,370)	(12,258)
Prior service cost	14	15	29	29
Net loss (gain)	2,157	1,001	4,315	2,003
Net periodic benefit cost	$1,563	$526	$3,126	$1,051

Defined Benefit Postretirement Healthcare Plans

The components of net periodic benefit cost for the Defined Benefit Postretirement Healthcare Plans were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Service cost	$572	$575	$1,145	$1,150
Interest cost	521	534	1,042	1,067
Expected return on plan assets	(56)	(79)	(113)	(158)
Prior service cost (benefit)	(99)	(109)	(198)	(218)
Net loss (gain)	54	125	108	250
Net periodic benefit cost	$992	$1,046	$1,984	$2,091

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

The components of net periodic benefit cost for the Supplemental Non-qualified Defined Benefit and Defined Contribution Plans were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Service cost	$435	$609	$715	$1,436
Interest cost	292	319	585	638
Prior service cost	1	—	1	1
Net loss (gain)	250	250	500	500
Net periodic benefit cost	$978	$1,178	$1,801	$2,575

For the three and six months ended June 30, 2018, service costs were recorded in Operations and maintenance expense while non-service costs were recorded in Other income (expense), net, on the Condensed Consolidated Statements of Income. For the three and six months ended June 30, 2017, service costs and non-service costs were recorded in Operations and maintenance expense. Because prior years' costs were not considered material, they were not reclassified on the Condensed Consolidated Statements of Income. See Note 1 for additional information.

Contributions

Contributions to the Defined Benefit Pension Plan are cash contributions made directly to the Pension Plan Trust account. On July 25, 2018, we made a contribution of approximately $13 million (included in the table below) to the Defined Benefit Pension Plan. Contributions to the Postretirement Healthcare and Supplemental Plans are made in the form of benefit payments. Contributions made in 2018 and anticipated contributions for 2018 and 2019 are as follows (in thousands):

	Contributions Made	Contributions Made	Additional Contributions	Contributions
	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018	Anticipated for 2018	Anticipated for 2019
Defined Benefit Pension Plan	$ —	$ —	$ 12,700	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,234	$ 2,468	$ 2,468	$ 4,802
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 343	$ 686	$ 686	$ 1,921

(17) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of June 30, 2018, we were in compliance with the debt covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our stockholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries.

Our utilities are generally limited to the amount of dividends allowed to be paid to us as a utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions and financing agreements. As of June 30, 2018, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

(18) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Loss from discontinued operations, net of income taxes in the accompanying Condensed Consolidated Statements of Income. Current assets, noncurrent assets, current liabilities and non-current liabilities of the discontinued operations have been reclassified and reflected on the accompanying Condensed Consolidated Balance Sheets as “Current assets held for sale,” “Noncurrent assets held for sale,” “Current liabilities held for sale,” and “Noncurrent liabilities held for sale”, respectively. Prior periods relating to our discontinued operations have also been reclassified to reflect consistency within our condensed consolidated financial statements.

Oil and Gas Segment

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of June 30, 2018, we have sold nearly all oil and gas assets. Transaction closing for the last few assets and final accounting are expected within the third quarter. The closing of the oil and gas office will occur in August. We expect to transfer any associated liabilities, and settle substantially all remaining liabilities by September 30, 2018.

In the process of divesting our Oil and Gas segment, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our recent sales of assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made and how they compared with the additional property sales occurring after December 31, 2017.

At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required an after-tax write down of $13 million. There were no further adjustments made to the fair value of our held for sale assets at June 30, 2018.

During the six months ended June 30, 2018, we recorded $2.2 million of expenses comprised of royalty payments and reclamation costs related to final closing on the sale of BHEP assets, which are presented as Loss on the sale of assets in the table below.

Total assets and liabilities of BHEP at June 30, 2018 and December 31, 2017 have been classified as Current assets held for sale and Current liabilities held for sale on the accompanying Condensed Consolidated Balance Sheets due to the expected final disposals occurring by September 30, 2018. Held for sale assets and liabilities at June 30, 2017 are classified as current and non-current (in thousands) as of.

	June 30, 2018	December 31, 2017	June 30, 2017
Other current assets	$378	$ 10,360	$8,193
Derivative assets, current and noncurrent	—	—	541
Deferred income tax assets, noncurrent, net	—	16,966	20,654
Property, plant and equipment, net	3,179	56,916	93,089
Other current liabilities	(4,295)	(18,966)	(10,860)
Derivative liabilities, current and noncurrent	—	—	(44)
Deferred income tax liabilities, noncurrent, net	(1,153)	—	—
Other noncurrent liabilities	—	(22,808)	(23,048)
Net assets (liabilities)	$(1,891)	$ 42,468	$88,525

At June 30, 2018, December 31, 2017 and June 30, 2017, the Oil and Gas segment’s net deferred tax assets and liabilities were primarily comprised of basis differences on oil and gas properties.

BHEP’s other current liabilities at June 30, 2018 consisted primarily of accrued royalties, payroll and property taxes. Current liabilities at December 31, 2017 consisted primarily of a liability contingent on final approval from the Bureau of Indian Affairs on the Jicarilla property sale, accrued royalties, payroll and property taxes. Current liabilities at June 30, 2017 consisted primarily of accrued royalties, payroll and property taxes. Other noncurrent liabilities at December 31, 2017 and June 30, 2017 consisted primarily of asset retirement obligations relating to plugging and abandonment of oil and gas wells.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Condensed Consolidated Statements of Income were as follows (in thousands) for the period ended:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue	$1,284	$6,149	$5,199	$12,624
Operations and maintenance	2,718	5,491	8,407	12,696
Loss (gain) on sale of assets	1,991	(249)	2,203	(249)
Depreciation, depletion and amortization	—	1,838	1,300	3,783
Total operating expenses	4,709	7,080	11,910	16,230
Operating (loss)	(3,425)	(931)	(6,711)	(3,606)
Other income (expense), net	90	65	119	138
Income tax benefit (expense)	908	250	1,822	1,283
(Loss) from discontinued operations	$(2,427)	$(616)	$(4,770)	$(2,185)

(19) INCOME TAXES

The effective tax rate differs from the federal statutory rate as follows:

	Three Months Ended June 30,	
Tax (benefit) expense	2018	2017
Federal statutory rate	21.0 %	35.0 %
State income tax (net of federal tax effect)	1.7	(0.1)
Percentage depletion in excess of cost	(0.4)	(1.2)
Noncontrolling interest [(a)]	(1.0)	(3.1)
Tax credits [(b)]	(2.1)	(3.6)
Effective tax rate adjustment [(c)]	—	4.4
Flow-through adjustments	(0.7)	(2.6)
TCJA change in estimate [(d)]	0.3	—
AFUDC equity	(0.1)	(0.6)
Other tax differences	0.7	0.9
	19.4 %	29.1 %

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(a) The adjustment reflects the non-controlling interest attributable to the sale of 49.9% of the membership interests of COIPP LLC in April 2016.

(b) The tax credits are due to the production tax credits for the Peak View wind farm.

(c) Adjustment to reflect our projected annual effective tax rate, pursuant to ASC 740-270.

(d) The TCJA was signed into law on December 22, 2017. In accordance with ASC 740, net deferred tax assets and liabilities were revalued as of December 31, 2017 due to the reduction in the federal income tax rate from 35% to 21%. During the three months ended June 30, 2018, certain estimated items associated with the revaluation have been updated.

	Six Months Ended June 30,	
Tax (benefit) expense	2018	2017
Federal statutory rate	21.0 %	35.0 %
State income tax (net of federal tax effect)	1.7	1.0
Percentage depletion in excess of cost	(0.4)	(0.6)
Noncontrolling interest	(1.0)	(1.6)
IRC 172(f) carryback claim [(a)]	—	(1.3)
Tax credits	(2.1)	(1.8)
Effective tax rate adjustment	—	(0.8)
Flow-through adjustments	(0.7)	(1.0)
TCJA change in estimate [(b)]	1.6	—
AFUDC equity	(0.1)	—
Jurisdictional simplification project [(c)]	(33.7)	—
Other tax differences	0.6	0.4
	(13.1)%	29.3 %

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(a) During the first quarter of 2017, the Company filed amended income tax returns for the years 2006 through 2008 to carryback specified liability losses in accordance with IRC172(f). As a result of filing the amended returns, the Company's accrued tax liability interest decreased, certain valuation allowances increased and the previously recorded domestic production activities deduction decreased.

(b) The TCJA was signed into law on December 22, 2017. In accordance with ASC 740, net deferred tax assets and liabilities were revalued as of December 31, 2017 due to the reduction in the federal income tax rate from 35% to 21%. During the six months ended June 30, 2018, certain estimated items associated with the revaluation have been updated.

(c) Tax benefit from legal restructuring associated with amortizable goodwill as part of ongoing jurisdictional simplification.

Tax benefit related to legal restructuring

As part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years, certain legal entity restructuring transactions occurred on March 31, 2018. As a result of these transactions, additional deferred income tax assets of $49 million, related to goodwill that is amortizable for tax purposes, were recorded and deferred tax benefits of $49 million were recorded to income tax benefit (expense) on the Condensed Consolidated Statements of Income. Due to this being a common control transaction, it had no effect on the other assets and liabilities of these entities.

TCJA

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. The Company remeasured deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position. We revalued our deferred tax assets and liabilities as of December 31, 2017, which reflected our estimate of the impact of the TCJA. We will continue to evaluate subsequent regulations, clarifications and interpretations with the assumptions made, which could materially change our estimate.

(20) ACCRUED LIABILITIES

The following amounts by major classification are included in Accrued liabilities in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2018	December 31, 2017	June 30, 2017
Accrued employee compensation, benefits and withholdings	$49,225	$52,467	$44,658
Accrued property taxes	34,664	42,029	32,440
Customer deposits and prepayments	36,993	44,420	41,068
Accrued interest and contract adjustment payments	33,767	33,822	33,914
CIAC current portion	1,552	1,552	1,575
Other (none of which is individually significant)	34,138	45,172	38,151
Total accrued liabilities	$190,339	$219,462	$191,806

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

We are a customer-focused, growth-oriented utility company operating in the United States. We report our operations and results in the following financial segments:

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 210,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities distribute and transport natural gas through our pipeline network to approximately 1,042,000 natural gas customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

Our Gas Utilities also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 52,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air conditioning, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Power Generation: Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts.

Mining: Our Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. All of our non-utility business segments support our utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for our electric utilities is June through August while the normal peak usage season for our gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2018 and 2017, and our financial condition as of June 30, 2018, December 31, 2017 and June 30, 2017, are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period or for the entire year.

See Forward-Looking Information in the Liquidity and Capital Resources section of this Item 2, beginning on Page 64.

The segment information does not include inter-company eliminations. Minor differences in amounts may result due to rounding. All amounts are presented on a pre-tax basis unless otherwise indicated.

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017. Net income from continuing operations available for common stock for the three months ended June 30, 2018 was $24 million, or $0.45 per diluted share, compared to $23 million, or $0.41 per diluted share, reported for the same period in 2017. The variance to the prior year included the following:

- Electric Utilities’ earnings increased $3.1 million driven primarily by recent transmission investments, higher commercial and industrial demand, and favorable weather, partially offset by higher operating expenses;
- Gas Utilities’ earnings decreased $0.9 million primarily due to higher operating expenses, partially offset by favorable weather and increased sales of natural gas;
- The Mining segment’s earnings increased $0.3 million primarily due to higher sales, partially offset by higher operating expenses; and
- Power Generation’s earnings decreased $0.6 million primarily due to higher maintenance expenses.

Net income available for common stock for the three months ended June 30, 2018 was $22 million, or $0.40 per diluted share, compared to $22 million, or $0.40 per diluted share reported for the same period in 2017. (Loss) from discontinued operations for the three months ended June 30, 2018 was $(2.4) million, or $(0.05) per diluted share compared to $(0.6) million or $(0.01) per diluted share reported for the same period in 2017.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017. Net income from continuing operations available for common stock for the six months ended June 30, 2018 was $160 million, or $2.94 per diluted share, compared to $101 million, or $1.83 per diluted share, reported for the same period in 2017. The variance to the prior year included the following:

- Gas Utilities’ earnings increased $61 million primarily due to the recognition of a deferred tax benefit of $49 million resulting from legal entity restructuring associated with amortizable goodwill for tax purposes; earnings also benefited from colder winter weather and increased sales of natural gas;
- Electric Utilities’ earnings increased $0.7 million driven primarily by recent transmission investments, higher commercial and industrial demand, and favorable weather, partially offset by higher operating expenses;
- Corporate and other expenses increased $1.8 million primarily due to higher tax benefits recognized in the prior year, partially offset by a reduction in corporate operating expenses; and
- Power Generation’s earnings decreased $1.2 million primarily due to lower MWh sold and higher operating expenses.

Net income available for common stock for the six months ended June 30, 2018 was $155 million, or $2.85 per diluted share, compared to $99 million, or $1.79 per diluted share reported for the same period in 2017. (Loss) from discontinued operations for the six months ended June 30, 2018 was $(4.8) million, or $(0.09) per diluted share compared to $(2.2) million or $(0.04) per diluted share reported for the same period in 2017.

The following table summarizes select financial results by operating segment and details significant items (in thousands):

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
Revenue						
Revenue	$390,019	$371,641	$18,378	$1,001,149	$952,688	$48,461
Inter-company eliminations	(34,315)	(29,812)	(4,503)	(70,056)	(63,331)	(6,725)
	$355,704	$341,829	$13,875	$931,093	$889,357	$41,736
Net income (loss) from continuing operations available for common stock						
Electric Utilities [b]	$21,890	$18,832	$3,058	$41,735	$41,062	$673
Gas Utilities [a]	(1,161)	(272)	(889)	106,459	45,738	60,721
Power Generation [b]	4,772	5,332	(560)	10,628	11,862	(1,234)
Mining [b]	3,005	2,681	324	5,989	5,571	418
	28,506	26,573	1,933	164,811	104,233	60,578
Corporate and Other [b]	(4,162)	(3,762)	(400)	(5,120)	(3,330)	(1,790)
Net income from continuing operations	24,344	22,811	1,533	159,691	100,903	58,788
(Loss) from discontinued operations, net of tax	(2,427)	(616)	(1,811)	(4,770)	(2,185)	(2,585)
Net income available for common stock	$21,917	$22,195	$(278)	$154,921	$98,718	$56,203

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(a) Net income (loss) from continuing operations for the six months ended June 30, 2018 included a $49 million tax benefit resulting from legal entity restructuring. See Note 19 of the Notes to Condensed Consolidated Financial Statements for more information.

(b) Net income (loss) from continuing operations for the six months ended June 30, 2018 included approximately $2.3 million of income tax expense recorded primarily as a result of an increase to a valuation allowance associated with tax reform related changes in estimated future taxable income. The impact to our operating segments and Corporate and Other was: Electric Utilities $0.4 million; Mining $0.5 million; Power Generation $0.7 million; and Corporate and Other $0.7 million.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- Electric Utilities experienced hotter summer weather during the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017. Cooling degree days for the three and six months ended June 30, 2018 were 109% higher than the 30-year average (normal) compared to 14% higher than normal for the same periods in 2017.

Heating degree days for the three and six months ended June 30, 2018 were 12% lower and 7% higher than normal compared to 9% and 11% lower than normal for the same periods in 2017.

- Wyoming Electric and Colorado Electric set new summer peak loads:

- On July 10, 2018, Wyoming Electric set a new all-time peak load of 254 MW, exceeding the previous summer peak of 249 MW set in July 2017.

- On June 27, 2018, Colorado Electric set a new all-time peak load of 413 MW, exceeding the previous summer peak of 412 MW set in July 2016.

- On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation to purchase 60 megawatts of wind energy through a 25-year power purchase agreement. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard.

- On July 25, 2018, South Dakota Electric placed in service the first 48-mile segment of a $70 million, 175-mile, 230-kilovolt transmission line from Rapid City, South Dakota, to Stegall, Nebraska. The remaining segment is expected to be in service by the end of 2019.

Gas Utilities Segment

- Rate Review updates:

- On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We expect the final order in the third quarter of 2018. The settlement provides for $1.0 million of new revenue, a return on equity of 9.6%, and a capital structure of 54.0% equity and 46.0% debt. New rates, inclusive of customer benefits related to the TCJA, will be effective September 1, 2018.

- In Colorado, new rates for RMNG went into effect June 1, 2018 after an administrative law judge recommended approval of a settlement agreement and the CPUC took no further action. The settlement included $1.1 million in annual revenue increases and an extension of SSIR to recover costs from 2018 through 2021. The annual increase is based on a return on equity of 9.9% and a capital structure of 46.63% equity and 53.37% debt.

- Arkansas Gas filed a rate review in December 2017 with the APSC requesting $30 million of annual revenue to recover more than $160 million of new infrastructure investment. The revenue request was subsequently adjusted to $19 million primarily related to a lower corporate income tax rate of 21%. The APSC previously issued a procedural schedule for the rate review. To date, testimony has been filed by the intervenors and Arkansas Gas filed rebuttal testimony on June 26, 2018. The APSC issued an order on July 26 requiring investor owned utilities to provide within 30 days their plans to return tax reform benefits to customers. Arkansas Gas is reviewing the order and its impacts to customers and may amend its current rate review if necessary. A final order and new rates are expected to be effective in the fourth quarter of 2018.

- Wyoming Gas filed for a CPCN on May 18, 2018 with the WPSC to construct a new $54 million, 35-mile natural gas pipeline (Natural Bridge Pipeline) to enhance reliability of supply for approximately 57,000 customers in its Casper division in central Wyoming.

- Certain legal entity restructuring transactions occurred on March 31, 2018 as part of the Company's ongoing efforts to continue to integrate the legal entities that the Company has acquired in recent years. As a result of these transactions, additional deferred income tax assets of $49 million, related to goodwill that is amortizable for tax purposes, were recorded with a corresponding deferred tax benefit recorded on the Condensed Consolidated Statements of Income.

- Gas Utilities experienced colder winter and spring weather during the three and six months ended June 30, 2018 compared to the three and six months ended June 30, 2017. Heating degree days for the three and six months ended June 30, 2018 were 1% lower and 1% higher than the 30-year average (normal) compared to 9% and 12% lower than normal for the same periods in 2017.

Power Generation

- On April 25, 2018, Black Hills Electric Generation was selected to provide 60 megawatts of renewable energy to Colorado Electric from a new wind project through a 25-year power purchase agreement. The $71 million Busch Ranch II wind project is expected to be in service by the end of 2019.

Corporate and Other

- On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former Revolving Credit Facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and the banks increasing or providing new commitments, to increase total commitments of the facility up to $1.0 billion.

- On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at June 30, 2018, matures on July 30, 2020.

- On July 19, 2018, Fitch affirmed South Dakota Electric's credit rating at A.

- On March 8, 2018, S&P affirmed Black Hills' credit rating at BBB and revised the outlook to Positive.

Discontinued Operations

- On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of June 30, 2018, we have sold nearly all oil and gas assets. Transaction closing for the last few assets and final accounting are expected within the third quarter. The closing of the oil and gas office will occur in August. See Note 18 of the Notes to Condensed Consolidated Financial Statements for more information.

Operating Results

A discussion of operating results from our segments and Corporate activities follows. Revenues for operating segments in the following sections are presented in total and by retail class. For disaggregation of revenue by contract type and operating segment, see Note 2 of the Notes to Condensed Consolidated Financial Statements for more information.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a "non-GAAP financial measure." Generally, a non-GAAP financial measure is a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation and amortization from the measure. The presentation of gross margin is intended to supplement investors' understanding of our operating performance.

Gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel and purchased power. Gross margin for our Gas Utilities is calculated as operating revenue less cost of natural gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies' gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue [a]	$173,616	$168,453	$5,163	$347,171	$344,477	$2,694
Total fuel and purchased power	64,283	62,265	2,018	131,406	130,665	741
Gross margin [b]	109,333	106,188	3,145	215,765	213,812	1,953
Operations and maintenance	45,101	44,315	786	90,194	85,098	5,096
Depreciation and amortization	24,640	23,120	1,520	49,153	45,981	3,172
Total operating expenses	69,741	67,435	2,306	139,347	131,079	8,268
Operating income	39,592	38,753	839	76,418	82,733	(6,315)
Interest expense, net	(13,209)	(12,893)	(316)	(26,500)	(26,305)	(195)
Other income (expense), net	(490)	590	(1,080)	(671)	930	(1,601)
Income tax benefit (expense)	(4,003)	(7,618)	3,615	(7,512)	(16,296)	8,784
Net income	$21,890	$18,832	$3,058	$41,735	$41,062	$673

(a) The three and six months ended June 30, 2018 include Horizon Point shared facility revenues of approximately $2.7 million and $5.3 million, respectively, which are allocated to all of our operating segments as facility expenses. This shared facility agreement has no impact on BHC's consolidated operating results.
(b) Non-GAAP measure

Results of Operations for the Electric Utilities for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Electric Utilities was $22 million for the three months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $19 million for the three months ended June 30, 2017, as a result of:

Gross margin increased primarily due to a $1.7 million increase in residential margins from warmer weather in the current year, higher rider revenues of $2.3 million primarily related to transmission investment recovery, higher commercial and industrial demand of $1.1 million and higher non-energy revenue of $2.9 million primarily from Horizon Point shared facility revenue (this shared facility revenue is offset by facility expenses at our operating segments and has no impact on consolidated results). These increases were partially offset by a $5.3 million reserve to revenue to reflect the lower federal income tax rate from the TCJA on our existing rate tariffs.

Operations and maintenance increased primarily due to higher facility costs of $1.3 million, partially offset by lower vegetation management expenses compared to the same period in the prior year.

Depreciation and amortization increased primarily due to a higher asset base driven by the prior year additions of Horizon Point and the Teckla-Lange transmission line.

Interest expense, net was comparable to the same period in the prior year.

Other income (expense), net decreased due to the presentation change of non-service pension costs to Other income (expense) in the current year, previously reported in Operations and maintenance, and higher prior year AFUDC associated with higher prior year capital spend.

Income tax benefit (expense): The effective tax rate decreased from the prior year due to the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Results of Operations for the Electric Utilities for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Electric Utilities was $42 million for the six months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $41 million for the six months ended June 30, 2017, as a result of:

Gross margin increased primarily due to a $3.3 million increase in residential margins from favorable weather in the current year, higher rider revenues of $3.5 million primarily related to transmission investment recovery, higher commercial and industrial demand of $0.6 million and higher non-energy revenue of $5.7 million primarily from Horizon Point shared facility revenue (this shared facility revenue is offset by facility expenses at our operating segments and has no impact on consolidated results). These increases were partially offset by an $11 million reserve to revenue to reflect the lower federal income tax rate from the TCJA on our existing rate tariffs.

Operations and maintenance increased primarily due to $2.1 million of higher vegetation management expenses and $2.6 million of shared facility costs. Higher employee costs and property taxes comprise the remainder of the increase compared to the same period in the prior year.

Depreciation and amortization increased primarily due to a higher asset base driven by the prior year additions of Horizon Point and the Teckla-Lange transmission line.

Interest expense, net was comparable to the same period in the prior year.

Other income (expense), net decreased due to the presentation change of non-service pension costs to Other income (expense) in the current year, previously reported in Operations and maintenance, and higher prior year AFUDC associated with higher prior year capital spend.

Income tax benefit (expense): The effective tax rate decreased from the prior year due to the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Operating Statistics

	Electric Revenue (in thousands)				Quantities sold (MWh)			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Residential	$50,116	$47,933	$105,857	$102,151	328,638	306,866	711,908	668,971
Commercial	64,902	63,938	126,886	127,451	509,984	485,205	1,010,120	989,279
Industrial	31,220	30,736	62,020	61,019	418,596	394,796	819,305	785,370
Municipal	4,666	4,676	8,807	8,976	42,657	40,704	78,981	77,676
Subtotal Retail Revenue - Electric	150,904	147,283	303,570	299,597	1,299,875	1,227,571	2,620,314	2,521,296
Contract Wholesale	8,191	6,702	17,241	14,545	218,132	165,881	455,836	351,997
Off-system/Power Marketing Wholesale	4,939	3,668	9,083	9,178	178,854	130,423	307,895	317,858
Other	9,582	10,800	17,277	21,157	—	—	—	—
Total Revenue and Energy Sold	173,616	168,453	347,171	344,477	1,696,861	1,523,875	3,384,045	3,191,151
Other Uses, Losses or Generation, net	—	—	—	—	125,606	116,642	216,461	219,977
Total Revenue and Energy	173,616	168,453	347,171	344,477	1,822,467	1,640,517	3,600,506	3,411,128

Less cost of fuel and purchased power	64,283	62,265	131,406	130,665
Gross Margin [(a)]	$109,333	$106,188	$215,765	$213,812

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(a) Non-GAAP measure

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Three Months Ended June 30,	Electric Revenue (in thousands)		Gross Margin (a) (in thousands)		Quantities Sold (MWh) (b)	
	2018	2017	2018	2017	2018	2017
South Dakota Electric	$70,676	$66,052	$49,922	$47,441	837,943	718,878
Wyoming Electric	40,408	40,351	21,951	22,439	441,996	423,157
Colorado Electric	62,532	62,050	37,460	36,308	542,528	498,482
Total Electric Revenue, Gross Margin, and Quantities Sold	$173,616	$168,453	$109,333	$106,188	1,822,467	1,640,517

(a) Non-GAAP measure

(b) Total MWh includes Other Uses, Losses or Generation, net, which are approximately 7%, 6%, and 7% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

Six Months Ended June 30,	Electric Revenue (in thousands)		Gross Margin (a) (in thousands)		Quantities Sold (MWh) (b)	
	2018	2017	2018	2017	2018	2017
South Dakota Electric	$144,491	$139,846	$101,298	$98,086	1,666,120	1,564,710
Wyoming Electric	81,795	82,629	43,646	45,225	904,858	863,064
Colorado Electric	120,885	122,002	70,821	70,501	1,029,528	983,354
Total Electric Revenue, Gross Margin, and Quantities Sold	$347,171	$344,477	$215,765	$213,812	3,600,506	3,411,128

(a) Non-GAAP measure

(b) Total MWh includes Other Uses, Losses or Generation, net, which are approximately 5%, 6%, and 7% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantities Generated and Purchased (MWh)	2018	2017	2018	2017
Coal-fired	568,733	466,265	1,164,333	1,038,345
Natural Gas and Oil	105,304	64,071	146,627	92,600
Wind	68,501	58,113	142,482	128,656
Total Generated	742,538	588,449	1,453,442	1,259,601
Purchased	1,079,929	1,052,068	2,147,064	2,151,527
Total Generated and Purchased	1,822,467	1,640,517	3,600,506	3,411,128

	Three Months Ended June 30,		Six Months Ended June 30,	
Quantities Generated and Purchased (MWh)	2018	2017	2018	2017
Generated:				
South Dakota Electric	411,839	300,564	824,033	698,899
Wyoming Electric	197,772	184,017	404,434	374,389
Colorado Electric	132,927	103,868	224,975	186,313
Total Generated	742,538	588,449	1,453,442	1,259,601
Purchased:				

South Dakota Electric	426,104	418,314	842,087	865,811
Wyoming Electric	244,224	239,140	500,424	488,675
Colorado Electric	409,601	394,614	804,553	797,041
Total Purchased	1,079,929	1,052,068	2,147,064	2,151,527
Total Generated and Purchased	1,822,467	1,640,517	3,600,506	3,411,128

Degree Days	Three Months Ended June 30, 2018				2017	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year		Actual	Variance from 30-Year Average
Heating Degree Days:						
South Dakota Electric	1,037	1 %	14%		910	(11)%
Wyoming Electric	1,053	(14)%	(10)%		1,164	(5)%
Colorado Electric	460	(27)%	(19)%		567	(10)%
Combined [(a)]	777	(12)%	(3)%		804	(9)%
Cooling Degree Days:						
South Dakota Electric	132	33 %	16%		114	15 %
Wyoming Electric	102	104 %	149%		41	(18)%
Colorado Electric	494	136 %	103%		243	16 %
Combined [(a)]	292	109 %	85%		158	14 %

(a) Combined actuals are calculated based on the weighted average number of total customers by state.

Degree Days	Six Months Ended June 30, 2018				2017	
	Actual	Variance from 30-Year Average	Actual Variance to Prior Year		Actual	Variance from 30-Year Average
Heating Degree Days:						
South Dakota Electric	4,736	12 %	17%		4,040	(5)%
Wyoming Electric	4,037	(9)%	4%		3,894	(12)%
Colorado Electric	2,866	12 %	7%		2,686	(17)%
Combined [(a)]	3,741	7 %	10%		3,391	(11)%
Cooling Degree Days:						
South Dakota Electric	132	33 %	16%		114	15 %
Wyoming Electric	102	104 %	149%		41	(18)%
Colorado Electric	494	136 %	103%		243	16 %
Combined [(a)]	292	109 %	85%		158	14 %

(a) Combined actuals are calculated based on the weighted average number of total customers by state.

Electric Utilities Power Plant Availability	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Coal-fired plants [(a)]	91.2%	74.8%	93.1%	83.0%
Natural gas-fired plants and Other plants	98.1%	94.5%	97.2%	96.5%
Wind	96.7%	93.4%	96.9%	92.4%
Total availability	95.8%	88.0%	95.9%	91.8%
Wind capacity factor	41.7%	35.8%	46.1%	39.7%

(a) 2017 included planned outages at Neil Simpson II, Wygen II and Wygen III.

Gas Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$161,212	$146,839	$14,373	$531,480	$479,535	$51,945
Other — non-regulated services (a)	16,408	19,608	(3,200)	43,484	51,822	(8,338)
Total revenue	177,620	166,447	11,173	574,964	531,357	43,607
Cost of sales:						
Natural gas — regulated	62,453	52,332	10,121	267,537	222,034	45,503
Other — non-regulated services (a)	5,601	10,018	(4,417)	10,202	21,698	(11,496)
Total cost of sales	68,054	62,350	5,704	277,739	243,732	34,007
Gross margin (b)	109,566	104,097	5,469	297,225	287,625	9,600
Operations and maintenance	71,667	64,956	6,711	142,573	135,715	6,858
Depreciation and amortization	21,414	20,924	490	42,724	41,721	1,003
Total operating expenses	93,081	85,880	7,201	185,297	177,436	7,861
Operating income	16,485	18,217	(1,732)	111,928	110,189	1,739
Interest expense, net	(19,257)	(19,610)	353	(39,023)	(39,392)	369
Other income (expense), net	(916)	(225)	(691)	(761)	(48)	(713)
Income tax benefit (expense)	2,527	1,346	1,181	34,315	(24,904)	59,219
Net income (loss)	(1,161)	(272)	(889)	106,459	45,845	60,614
Net (income) loss attributable to noncontrolling interest	—	—	—	—	(107)	107
Net income (loss) available for common stock	$(1,161)	$(272)	$(889)	$106,459	$45,738	$60,721

(a) The three and six months ended June 30, 2018 include certain BHES trading activities which are reported on a net basis. These trading activities are presented on a gross basis in the prior year. This change in presentation had no impact on gross margin.

(b) Non-GAAP measure

Results of Operations for the Gas Utilities for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net (loss) from continuing operations available for common stock for the Gas Utilities was $(1.2) million for the three months ended June 30, 2018, compared to Net loss from continuing operations available for common stock of $(0.3) million for the three months ended June 30, 2017, as a result of:

Gross margin benefited from a $2.8 million increase driven by higher natural gas volumes sold and a $0.9 million weather impact from colder spring temperatures as our service territories experienced colder weather in the current period compared to the same period in the prior year. Heating degree days were 1 percent below normal in the current year compared to 9 percent below normal for the same period in the prior year. Compared to the prior year, mark-to-market gains on non-utility natural gas commodity contracts increased $1.6 million, customer growth added $1.0 million in additional margin and rider revenues increased by $1.3 million primarily from our capital integrity recovery riders. These increases compared to the prior year are partially offset by a $2.2 million current year reserve to revenue to reflect the reduction of the lower federal income tax rate from the TCJA on our existing utility rate tariffs.

Operations and maintenance increased primarily due to higher employee costs of approximately $3.3 million driven primarily by labor, benefits and increased corporate allocations. Other increases compared to the prior year were from bad debt expense, which increased approximately $1.5 million driven by the current year increase in revenues, an increase in net facility costs of $1.3 million and higher property taxes.

Depreciation and amortization increased due to a higher asset base driven by previous year capital expenditures.

Interest expense, net was comparable to the same period in the prior year.

Other income (expense), net decreased from the prior year due primarily to the presentation change of non-service pension costs to Other income (expense) in the current year, previously reported in Operations and maintenance.

Income tax benefit (expense) increased from the prior year due to greater flow through benefits and lower state taxes, partially offset by the lower tax rate as a result of the reduction of the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Results of Operations for the Gas Utilities for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Gas Utilities was $106 million for the six months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $46 million for the six months ended June 30, 2017, as a result of:

Gross margin increased primarily due to a $10 million weather impact from colder winter temperatures as our service territories experienced colder weather in the current period compared to the same period in the prior year. Heating degree days were 1 percent higher than normal in the current year compared to 12 percent below normal for the same period in the prior year. An increase in natural gas volumes sold added $2.3 million, customer growth added $2.8 million in additional margin over the prior year, rider revenues increased by $3.1 million primarily from our capital integrity recovery riders and mark-to-market gains on non-utility natural gas commodity contracts increased $2.5 million. These increases over the prior year are partially offset by a $11 million current year reserve to revenue to reflect the reduction of the lower federal income tax rate from the TCJA on our existing rate tariffs.

Operations and maintenance increased primarily due to higher employee costs of approximately $3.6 million driven by labor, benefits and increased corporate allocations, higher bad debt expense of approximately $2.1 million driven by the current year increase in revenues and a net increase in facility costs of $2.8 million. These increases are partially offset by lower outside service expenses of approximately $1.8 million.

Depreciation and amortization increased due to a higher asset base driven by previous year capital expenditures.

Interest expense, net was comparable to the same period in the prior year.

Other income (expense), net decreased from the prior year due to the presentation change of non-service pension costs to Other income (expense) in the current year, previously reported in Operations and maintenance.

Income tax benefit (expense): The 2018 tax benefit is due to legal restructuring to enable jurisdictional simplification that resulted in the recognition of a deferred tax benefit of approximately $49 million associated with amortizable goodwill for tax purposes. The current year effective tax rate also reflects the reduction of the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Operating Statistics

	Gas Revenue (in thousands)				Gross Margin (a) (in thousands)			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Residential	$91,000	$81,251	$325,751	$286,603	$52,697	$49,193	$149,474	$140,244
Commercial	34,031	31,054	129,036	112,790	14,807	14,035	47,010	43,834
Industrial	6,565	4,281	12,547	9,227	1,639	1,026	3,313	2,508
Other (b)	255	1,876	(7,276)	4,264	255	1,876	(7,276)	4,264
Total Distribution	131,851	118,462	460,058	412,884	69,398	66,130	192,521	190,850
Transportation and Transmission	29,361	28,377	71,422	66,651	29,361	28,377	71,422	66,651
Total Regulated	161,212	146,839	531,480	479,535	98,759	94,507	263,943	257,501
Non-regulated Services	16,408	19,608	43,484	51,822	10,807	9,590	33,282	30,124
Total Gas Revenue & Gross Margin	$177,620	$166,447	$574,964	$531,357	$109,566	$104,097	$297,225	$287,625

(a) Non-GAAP measure

(b) Includes current year reserve to revenue to reflect the reduction of the lower federal income tax rate from the TCJA on our existing rate tariffs.

	Revenue (in thousands)				Gross Margin (a) (in thousands)			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Arkansas	$27,095	$24,145	$97,483	$85,243	$16,471	$15,568	$52,388	$52,877
Colorado	32,138	31,665	103,536	98,844	18,562	18,810	51,707	53,173
Nebraska	48,993	45,396	155,754	143,711	32,801	29,376	86,661	79,128
Iowa	27,102	23,462	94,986	80,910	14,648	14,262	37,074	35,714
Kansas	21,002	18,326	63,383	57,275	11,870	11,140	29,767	28,603
Wyoming	21,290	23,453	59,822	65,374	15,214	14,941	39,628	38,130
Total Gas Revenue & Gross Margin	$177,620	$166,447	$574,964	$531,357	$109,566	$104,097	$297,225	$287,625

(a) Non-GAAP measure

	Three Months Ended June 30,		Six Months Ended June 30,	
Gas Utilities Quantities Sold & Transported (Dth)	2018	2017	2018	2017
Residential	8,837,588	7,101,336	38,933,825	32,369,470
Commercial	4,615,571	3,960,957	18,564,692	15,665,271
Industrial	1,747,702	1,041,032	2,931,319	1,967,919

Total Distribution Quantities Sold	15,200,861	12,103,325	60,429,836	50,002,660
Transportation and Transmission	32,846,279	30,924,304	77,579,754	71,737,178
Total Quantities Sold & Transported	48,047,140	43,027,629	138,009,590	121,739,838

Gas Utilities Quantities Sold & Transported (Dth)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Arkansas	5,282,607	5,069,939	17,161,233	14,282,024
Colorado	4,705,454	5,057,411	16,408,805	16,045,055
Nebraska	16,405,326	13,908,566	44,392,550	38,181,355
Iowa	7,429,328	6,631,758	22,932,317	20,126,770
Kansas	6,929,756	5,196,050	17,227,084	13,705,368
Wyoming	7,294,669	7,163,905	19,887,601	19,399,266
Total Quantities Sold & Transported	48,047,140	43,027,629	138,009,590	121,739,838

Our Gas Utilities are highly seasonal, and sales volumes vary considerably with weather and seasonal heating and industrial loads. Approximately 70% of our Gas Utilities' revenue and margins are expected in the first and fourth quarters of each year. Therefore, revenue for, and certain expenses of, these operations fluctuate significantly among quarters. Depending upon the geographic location in which our Gas Utilities operate, the winter heating season begins around November 1 and ends around March 31.

Degree Days	Three Months Ended June 30, 2018			2017	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a]	400	21%	65%	242	(27)%
Colorado	735	(23)%	(17)%	889	(7)%
Nebraska	708	12%	25%	567	(11)%
Iowa	801	17%	29%	619	(10)%
Kansas [a]	508	14%	14%	445	—%
Wyoming	1,072	(12)%	(9)%	1,177	(4)%
Combined [b]	740	(1)%	8%	686	(9)%

Degree Days	Six Months Ended June 30, 2018			2017	
Heating Degree Days:	Actual	Variance from 30-Year Average	Actual Variance to Prior Year	Actual	Variance from 30-Year Average
Arkansas [a]	2,448	1 %	35%	1,811	(26)%
Colorado	3,439	(12)%	3%	3,354	(14)%
Nebraska	3,915	7 %	22%	3,214	(12)%
Iowa	4,332	7 %	22%	3,551	(13)%
Kansas [a]	2,978	2 %	17%	2,547	(13)%
Wyoming	4,316	(2)%	4%	4,161	(6)%
Combined [b]	3,899	1 %	15%	3,404	(12)%

(a) Arkansas has a weather normalization mechanism in effect during the months of November through April for customers with residential and business rate schedules. Kansas Gas has a weather normalization mechanism within its residential and business rate structure, which minimizes weather impact on gross margins. The weather normalization mechanism in Arkansas differs from that in Kansas in that it only uses one location to calculate the weather, compared to Kansas, which uses multiple locations. The weather normalization mechanism in Arkansas minimizes weather impact, but does not eliminate the impact.

(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism. Arkansas Gas is partially excluded based on the weather normalization mechanism in effect from November through April.

Regulatory Matters

For more information on recent regulatory activity and enacted regulatory provisions with respect to the states in which our Utilities operate, see Note 5 of the Notes to Condensed Consolidated Financial Statements of this Quarterly Report on Form 10-Q and Part I, Items 1 and 2 and Part II, Item 8 of our 2017 Annual Report on Form 10-K filed with the SEC.

Power Generation

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue [(a)]	$21,884	$21,795	$ 89	$44,987	$45,362	$(375)
Operations and maintenance	9,959	8,528	1,431	18,086	16,582	1,504
Depreciation and amortization [(a)]	1,633	1,069	564	3,235	2,276	959
Total operating expense	11,592	9,597	1,995	21,321	18,858	2,463
Operating income	10,292	12,198	(1,906)	23,666	26,504	(2,838)
Interest expense, net	(1,316)	(704)	(612)	(2,489)	(1,291)	(1,198)
Other income (expense), net	(47)	(13)	(34)	(41)	(31)	(10)
Income tax (expense) benefit	(1,334)	(3,033)	1,699	(4,055)	(6,688)	2,633
Net income	7,595	8,448	(853)	17,081	18,494	(1,413)
Net income attributable to noncontrolling interest	(2,823)	(3,116)	293	(6,453)	(6,632)	179
Net income available for common stock	$4,772	$5,332	$ (560)	$10,628	$11,862	$(1,234)

(a) The generating facility located in Pueblo, Colorado is accounted for as a capital lease under GAAP; as such, revenue and depreciation expense are impacted by the accounting for this lease. Under the lease, the original cost of the facility is recorded at Colorado Electric and is being depreciated by Colorado Electric for segment reporting purposes.

In 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Colorado IPP. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Colorado Electric. Net income available for common stock for the three months ended June 30, 2018 and June 30, 2017 was reduced by $2.8 million and $3.1 million, respectively, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Power Generation segment was $4.8 million for the three months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $5.3 million for the same period in 2017. Revenue was comparable to the same period in the prior year. Operating expenses increased from the same period in the prior year due to higher maintenance expenses primarily related to outage costs at Wygen I, turbine maintenance expenses at the generating facility in Pueblo and higher depreciation. Interest expense increased from the same period in the prior year due to higher interest rates. The variance in tax expense reflects the reduction in the federal tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Results of Operations for Power Generation for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Power Generation segment was $11 million for the six months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $12 million for the same period in 2017. Revenue decreased in the current year as a result of lower Wygen I MWh sold due to current year outages. Operating expenses increased from the same period in the prior year due to higher maintenance expenses primarily related to outage costs at Wygen I and higher depreciation. Interest expense increased from the same period in the prior year due to higher interest rates. The variance in tax expense reflects the reduction in the federal tax rate from 35% to 21% from the TCJA, effective January 1, 2018, partially offset by $0.7 million of additional tax expense recorded on a valuation allowance due to changes in estimated future taxable income subsequent to the TCJA.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Quantities Sold, Generated and Purchased (MWh) [a]				
Sold				
Black Hills Colorado IPP [b]	208,888	214,059	441,263	469,024
Black Hills Wyoming [c]	144,460	142,593	310,061	312,969
Total Sold	353,348	356,652	751,324	781,993
Generated				
Black Hills Colorado IPP [b]	208,888	214,059	441,263	469,024
Black Hills Wyoming [c]	128,819	127,454	262,848	267,694
Total Generated	337,707	341,513	704,111	736,718
Purchased				
Black Hills Colorado IPP	—	—	—	—
Black Hills Wyoming [c]	17,122	10,962	49,039	32,217
Total Purchased	17,122	10,962	49,039	32,217

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(a) Company uses and losses are not included in the quantities sold, generated, and purchased.

(b) Decrease from the prior year is a result of the impact of Colorado Electric's wind generation replacing natural-gas generation.

(c) Under the 20-year economy energy PPA with the City of Gillette effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette. MWh sold may not equal MWh generated and purchased due to a dispatch agreement Black Hills Wyoming has with South Dakota Electric to cover energy imbalances.

The following table provides certain operating statistics for our plants within the Power Generation segment:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Contracted power plant fleet availability:				
Coal-fired plant	89.1 %	90.4 %	91.9 %	95.2 %
Natural gas-fired plants	99.5 %	99.1 %	99.5 %	99.1 %
Total availability	96.8 %	96.9 %	97.5 %	98.1 %

Mining

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue	$16,899	$14,946	$1,953	$34,027	$31,492	$2,535
Operations and maintenance	11,124	9,833	1,291	22,046	20,927	1,119
Depreciation, depletion and amortization	1,950	2,062	(112)	3,885	4,227	(342)
Total operating expenses	13,074	11,895	1,179	25,931	25,154	777
Operating income	3,825	3,051	774	8,096	6,338	1,758
Interest expense, net	(233)	(74)	(159)	(333)	(99)	(234)
Other income (expense), net	(94)	536	(630)	(120)	1,077	(1,197)
Income tax benefit (expense)	(493)	(832)	339	(1,654)	(1,745)	91
Net income	$3,005	$2,681	$324	$5,989	$5,571	$418

The following table provides certain operating statistics for our Mining segment (in thousands, except for Revenue per ton):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Tons of coal sold	963	927	2,041	1,976
Cubic yards of overburden moved	2,380	1,961	4,402	4,065
Revenue per ton	$16.97	$16.12	$16.12	$15.94

Results of Operations for Mining for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Mining segment was $3.0 million for the three months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $2.7 million for the same period in 2017. Revenue increased due to a 4% increase in tons sold and a 5% increase in price per ton sold driven by contract price adjustments based on actual mining costs. Current year revenue is also reflective of lease and rental revenue, previously reported in Other income (expense), net. During the current period, approximately 51% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operating expenses increased primarily due to increased overburden removal and higher royalties and production taxes on increased revenues. Other income (expense), net decreased from the prior year due to the presentation change of lease and rental revenue to revenue in the current year, previously reported in other income (expense), net. The variance in tax expense to the prior year reflects the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018.

Results of Operations for Mining for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net income from continuing operations available for common stock for the Mining segment was $6.0 million for the six months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $5.6 million for the same period in 2017. Revenue increased due to a 3% increase in tons sold and a 1% increase in price per ton sold. Current year revenue is also reflective of lease and rental revenue, previously reported in Other income (expense), net. During the current period, approximately 49% of the mine’s production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operating expenses increased primarily due to increased overburden removal and higher royalties and production taxes on increased revenues. Other income (expense), net decreased from the prior year due to the presentation change of lease and rental revenue to Revenue in the current year, previously reported in Other income (expense), net. The variance in tax expense to the prior year reflects the reduction in the federal corporate income tax rate from 35% to 21% from the TCJA, effective January 1, 2018, partially offset by $0.5 million of additional tax expense related to previous years' other comprehensive items pursuant to the TCJA.

Corporate and Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Operating (loss) [(a)]	$(645)	$(2,423)	$1,778	$(2,285)	$(5,782)	$3,497
Other income (expense):						
Interest (expense) income, net [(a)]	(519)	(653)	134	(1,184)	(1,303)	119
Other income (expense), net	240	(171)	411	182	(838)	1,020
Income tax benefit (expense)	(3,238)	(515)	(2,723)	(1,833)	4,593	(6,426)
Net income (loss)	$(4,162)	$(3,762)	$(400)	$(5,120)	$(3,330)	$(1,790)

(a) Includes certain general and administrative expenses and interest expenses that are not reported as discontinued operations.

Results of Operations for Corporate and Other for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net loss from continuing operations available for common stock for Corporate and Other was $(4.2) million for the three months ended June 30, 2018, compared to Net income from continuing operations available for common stock of $(3.8) million for the three months ended June 30, 2017. The variance was driven by higher prior year operating costs previously allocated to BHEP which were not reclassified to discontinued operations. Income tax benefit (expense) increased in the current year due to higher state income tax expense impacting our quarterly adjustment to the projected annual effective tax rate.

Results of Operations for Corporate and Other for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net loss from continuing operations available for common stock for Corporate and Other was $(5.1) million for the six months ended June 30, 2018, compared to Net loss from continuing operations available for common stock of $(3.3) million for the six months ended June 30, 2017. The variance to the prior year was driven by higher prior year operating costs previously allocated to BHEP which were not reclassified to discontinued operations and transition and acquisition expenses which occurred in the prior year. The variance in Income tax benefit (expense) was primarily due to a prior year tax benefit of $1.4 million comprised primarily of benefits from a carryback claim for specified liability losses involving prior tax years, current year tax expense driven primarily by the adjustment to the projected annual effective tax rate compared to a tax benefit recorded in the prior year, and approximately $0.6 million of current year tax expense recorded pursuant to the TCJA.

Discontinued Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue	$1,284	$6,149	$(4,865)	$5,199	$12,624	$(7,425)
Operations and maintenance	2,718	5,491	(2,773)	8,407	12,696	(4,289)
Loss (gain) on sale of operating assets	1,991	(249)	2,240	2,203	(249)	2,452
Depreciation, depletion and amortization	—	1,838	(1,838)	1,300	3,783	(2,483)
Total operating expenses	4,709	7,080	(2,371)	11,910	16,230	(4,320)
Operating (loss)	(3,425)	(931)	(2,494)	(6,711)	(3,606)	(3,105)
Other income (expense), net	90	65	25	119	138	(19)
Income tax benefit (expense)	908	250	658	1,822	1,283	539
(Loss) from discontinued operations available for common stock	$(2,427)	$(616)	$(1,811)	$(4,770)	$(2,185)	$(2,585)

Results of Discontinued Operations for the Three Months Ended June 30, 2018 Compared to the Three Months Ended June 30, 2017: Net loss from discontinued operations was $(2.4) million for the three months ended June 30, 2018, compared to Net loss from discontinued operations of $(0.6) million for the same period in 2017. The variance to the prior year is driven by lower revenues due to current year and prior year property sales and higher losses on sales of operating assets, partially offset by lower oil and gas operating expenses and lower employee costs. Depreciation and depletion expense in the prior year is reflective of full cost accounting, which continued through November 1, 2017.

Results of Discontinued Operations for the Six Months Ended June 30, 2018 Compared to the Six Months Ended June 30, 2017: Net loss from discontinued operations was $(4.8) million for the six months ended June 30, 2018, compared to Net loss from discontinued operations of $(2.2) million for the same period in 2017. The variance to the prior year is driven by lower revenues due to current year and prior year property sales and higher losses on sales of operating assets, partially offset by lower oil and gas operating expenses and lower employee costs. Current year depreciation expense is representative of the write-down of the remaining book value of accounting software. Depreciation and depletion expense in the prior year is reflective of full cost accounting, which continued through November 1, 2017.

Critical Accounting Estimates

There have been no material changes in our critical accounting estimates from those reported in our 2017 Annual Report on Form 10-K filed with the SEC. For more information on our critical accounting estimates, see Part II, Item 7 of our 2017 Annual Report on Form 10-K.

Liquidity and Capital Resources

OVERVIEW

Our Company requires significant cash to support and grow our business. Our predominant source of cash is supplied by our operations and supplemented with corporate financings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations, and redemption of outstanding debt and equity securities when required or financially appropriate. As discussed in more detail below under income taxes, we expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices, as well as during the summer construction season.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies, and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow; however, the potential for unforeseen events affecting cash needs will continue to exist.

Our utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At June 30, 2018, we had sufficient liquidity to cover collateral that could be required to be posted under these contracts.

Income Tax

The TCJA legislation was signed into law on December 22, 2017. The new tax law required revaluation at December 31, 2017 of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets as specifically prescribed in the TCJA.

We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. We estimate the lower tax rate will negatively impact the Company’s cash flows by approximately $35 million to $45 million annually for the next several years. Each of our utilities is working with their respective regulators to address the impact of tax reform and the appropriate benefit to customers. See Note 5 for more information on regulatory matters.

Cash Flow Activities

The following table summarizes our cash flows for the three months ended June 30 (in thousands):

Cash provided by (used in):	2018	2017	Increase (Decrease)
Operating activities	$310,701	$262,869	$47,832
Investing activities	$(163,526)	$(163,530)	$4
Financing activities	$(153,701)	$(101,069)	$(52,632)

Year-to-Date 2018 Compared to Year-to-Date 2017

Operating Activities

Net cash provided by operating activities was $311 million for the six months ended June 30, 2018, compared to net cash provided by operating activities of $263 million for the same period in 2017 for a variance of $48 million. The variance was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $0.8 million lower for the six months ended June 30, 2018 compared to the same period in the prior year;

- Net cash inflows from changes in operating assets and liabilities were $47 million for the six months ended June 30, 2018, compared to net cash outflows of $6 million in the same period in the prior year. This $53 million variance was primarily due to:

Cash inflows decreased by approximately $33 million primarily as a result of increases in our accounts receivable and other operating assets driven by current year increase in revenues, partially offset by lower natural gas in storage for the six months ended June 30, 2018 compared to the same period in the prior year;

Cash outflows decreased by approximately $21 million as a result of increases in accounts payable and accrued liabilities driven by changes in working capital requirements; and

Cash inflows increased by approximately $67 million as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and cash collected from customers on billings that do not reflect benefits of the TCJA compared to the same period in the prior year.

Investing Activities

Net cash used in investing activities was $164 million for the six months ended June 30, 2018, compared to net cash used in investing activities of $164 million for the same period in 2017. These were approximately the same due to:

- Capital expenditures of approximately $157 million for the six months ended June 30, 2018 compared to $154 million for the same period in the prior year. Higher current year expenditures at our gas utilities are offset by higher prior expenditures at our electric utilities which included completion of the second segment of the 144-mile long Teckla-Lange transmission line and construction of our Horizon Point facility.

- A $24 million investment partially offset by a $27 million change in net cash provided by investing activities from discontinued operations primarily due to the sale of assets held for sale.

Financing Activities

Net cash used in financing activities for the six months ended June 30, 2018 was $154 million, compared to $101 million of net cash used in financing activities for the same period in 2017 for a variance of $53 million. This variance is primarily due to higher current year short-term debt repayments of $101 million, partially offset by a $50 million term loan payment in the prior year and higher current year dividend payments.

Dividends

Dividends paid on our common stock totaled $51 million for the six months ended June 30, 2018, or $0.475 per share per quarter. On July 25, 2018, our board of directors declared a quarterly dividend of $0.475 per share payable September 1, 2018, equivalent to an annual dividend of $1.90 per share. The amount of any future cash dividends to be declared and paid, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our Revolving Credit Facility and our future business prospects.

Debt

Financing Transactions and Short-Term Liquidity

Our principal sources to meet day-to-day operating cash requirements are cash from operations, our CP Program and our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On July 30, 2018, we amended and restated our corporate Revolving Credit Facility, maintaining total commitments of $750 million and extending the term through July 30, 2023 with two one-year extension options (subject to consent from lenders). This facility is similar to the former revolving credit facility, which includes an accordion feature that allows us, with the consent of the administrative agent, the issuing agents and each bank increasing or providing a new commitment, to increase total commitments up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. See Note 9 for more information.

We have a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. See Note 9 for more information.

Our Revolving Credit Facility had the following borrowings, outstanding letters of credit, and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at June 30, 2018	CP Program Borrowings at June 30, 2018	Letters of Credit at June 30, 2018	Available Capacity at June 30, 2018
Revolving Credit Facility	July 30, 2023	$ 750	$ —	$ 122	$ 11	$ 617

The weighted average interest rate on CP Program borrowings at June 30, 2018 was 2.29%. Revolving Credit Facility and CP Program financing activity for the six months ended June 30, 2018 was (dollars in millions):

	For the Six Months Ended June 30, 2018
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$ 231
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances)	$ —

Average amount outstanding - commercial paper (based on daily outstanding balances)	$ 146
Average amount outstanding - revolving credit facility (based on daily outstanding balances)	$ —
Weighted average interest rates - commercial paper	2.13 %
Weighted average interest rates - revolving credit facility	— %

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness (which includes letters of credit and certain guarantees issued but excludes the RSNs), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs or, with respect to the calculation as of September 30, 2018 only, the amount receivable by the Company in connection with the common stock settlement under the purchase contracts which are part of the Equity Units). Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of June 30, 2018.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Financing Activities

Financing activities for the six months ended June 30, 2018 consisted of short-term borrowings from our CP Program. On August 4, 2017, we renewed the ATM equity offering program which reset the size of the ATM equity offering program to an aggregate value of up to $300 million. We did not issue any shares of common stock under our ATM equity offering program for the six months ended June 30, 2018.

On July 30, 2018, we amended and restated our unsecured term loan due August 2019. This amended and restated term loan, with $300 million outstanding at June 30, 2018, will now mature July 30, 2020 and has substantially similar terms and covenants as the amended and restated Revolving Credit Facility. See Note 9 for more information.

Future Financing Plans

The terms of the Equity Units require us to remarket the RSNs on behalf of the holders of the Equity Units in advance of November 1, 2018, the scheduled settlement of the purchase contracts included in the Equity Units. We intend to satisfy this requirement by conducting an optional remarketing of the RSNs. We will not directly receive the proceeds of the remarketing. Instead, the proceeds from the sale of the RSNs will be invested on behalf of the holders of our Equity Units in a portfolio of treasury securities, which will be pledged to secure (and may eventually be used to satisfy) the obligations of the holders of the Equity Units to purchase $299 million of our common stock on November 1, 2018 in settlement of the purchase contracts included in the Equity Units. We anticipate using the net proceeds from such settlement to pay down debt and for general corporate purposes.

In connection with the optional remarketing of the RSNs, we also expect to undertake a series of transactions that may result in the exchange or modification of the RSNs, which would result in modification of the interest rate, maturity, covenants, seniority, and other terms, and may also include the issuance of additional senior unsecured notes of the same series as the RSNs as so modified. We anticipate using any net proceeds from the issuance of any such additional senior unsecured notes to pay down debt and for general corporate purposes.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. Our utilities in Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. The use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary’s liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. As of June 30, 2018, the restricted net assets at our Electric Utilities and Gas Utilities were approximately $257 million.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not meet certain financial covenants. The only financial covenant under our Revolving Credit Facility and existing term loan is a Consolidated Indebtedness to Capitalization Ratio, which requires us to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00 at the end of any fiscal quarter. Our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness (which includes letters of credit and certain guarantees issued but excludes the RSNs), by (ii) Capital, which is Consolidated Indebtedness plus Consolidated Net Worth (which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs or, with respect to the calculation as of September 30, 2018 only, the amount receivable by the Company in connection with the common stock settlement under the purchase contracts which are part of the

Equity Units). Additionally, covenants within Cheyenne Light's financing agreements require Cheyenne Light to maintain a debt to capitalization ratio of no more than 0.60 to 1.00. As of June 30, 2018, we were in compliance with these covenants.
There have been no other material changes in our financing transactions and short-term liquidity from those reported in Item 7 of our 2017 Annual Report on Form 10-K filed with the SEC.

Credit Ratings

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect our ability to maintain or expand our businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and the credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings and outlook and risk profile of BHC at June 30, 2018:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Positive
Moody's[(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Stable

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(a) On March 8, 2018, S&P affirmed BBB rating and revised the outlook to Positive.
(b) On December 12, 2017, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On October 4, 2017, Fitch affirmed BBB+ rating and maintained a Stable outlook.

The following table represents the credit ratings of South Dakota Electric at June 30, 2018:

Rating Agency	Senior Secured Rating
S&P	A-
Moody's	A1
Fitch [(a)]	A

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(a) On July 19, 2018, Fitch affirmed A rating.

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Capital Requirements

Capital Expenditures

Actual and forecasted capital requirements are as follows (in thousands):

	Expenditures for the Six Months Ended June 30, 2018 [a]	Total 2018 Planned Expenditures [b]	Total 2019 Planned Expenditures	Total 2020 Planned Expenditures
Electric Utilities	$ 55,729	$ 149,000	$ 193,000	$ 141,000
Gas Utilities [d]	98,691	268,000	328,000	245,000
Power Generation [c]	1,721	32,000	56,000	5,000
Mining	6,210	19,000	7,000	7,000
Corporate and Other	5,075	10,000	13,000	8,000
	$ 167,426	$ 478,000	$ 597,000	$ 406,000

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(a) Expenditures for the six months ended June 30, 2018 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the six months ended June 30, 2018.
(c) Planned capital expenditures for 2018 and 2019 increased due to the Busch Ranch II wind project.
(d) Planned capital expenditures for 2018 and 2019 increased due to the Natural Bridge Pipeline project.

We continue to evaluate potential future acquisitions and other growth opportunities when they arise. As a result, capital expenditures may vary significantly from the estimates identified above.

Contractual Obligations

There have been no significant changes in contractual obligations from those previously disclosed in Note 19 of our Notes to the Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

Guarantees

There have been no significant changes to guarantees from those previously disclosed in Note 20 of the Notes to the Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

New Accounting Pronouncements

Other than the pronouncements reported in our 2017 Annual Report on Form 10-K filed with the SEC and those discussed in Note 1 of the Notes to Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q, there have been no new accounting pronouncements that are expected to have a material effect on our financial position, results of operations, or cash flows.

FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and inc statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 2 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date the statement was made. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement was made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements described in our 2017 Annual Report on Form 10-K including statements contained within Item 1A - Risk Factors of our 2017 Annual Report on Form 10-K, Part II, Item 1A of this Quarterly Report on Form 10-Q and other reports that we file with the SEC from time to time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Utilities

Our utility customers are exposed to natural gas price volatility. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options and basis swaps to reduce our customers' underlying exposure to these fluctuations. We also reduce the commodity price risk in the unregulated area of our business by using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales. The fair value of our utilities' derivative contracts is summarized below (in thousands) as of:

	June 30, 2018	December 31, 2017	June 30, 2017
Net derivative (liabilities) assets	$(5,117)	$(6,644)	$(7,075)
Cash collateral offset in Derivatives	3,997	7,694	6,950
Cash collateral included in Other current assets	1,913	562	2,339
Net asset (liability) position	$793	$1,612	$2,214

Financing Activities

Historically, we have entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations and anticipated debt refinancings. At June 30, 2018, December 31, 2017 and June 30, 2017, we had no outstanding interest rate swap agreements.

ITEM 4. CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) as of June 30, 2018. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at June 30, 2018.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2018, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

BLACK HILLS CORPORATION

Part II — Other Information

ITEM 1. Legal Proceedings

For information regarding legal proceedings, see Note 19 in Item 8 of our 2017 Annual Report on Form 10-K and Note 17 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 17 is incorporated by reference into this item.

ITEM 1A. Risk Factors

There are no material changes to the risk factors previously disclosed in Item 1A of Part I in our 2017 Annual Report on Form 10-K filed with the SEC.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

There were no unregistered securities sold during the six months ended June 30, 2018.

ITEM 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Quarterly Report on Form 10-Q.

ITEM 5. Other Information

None.

ITEM 6. Exhibits

Exhibit Number	Description
Exhibit 3.1*	Restated Articles of Incorporation of the Registrant dated January 30, 2018 (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
Exhibit 3.2*	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
Exhibit 4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016). Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
Exhibit 4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S 3 (No. 333 150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014).

	Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
Exhibit 4.4*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

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Exhibit 4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015).
Exhibit 4.6*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
Exhibit 10.1	Third Amended and Restated Credit Agreement dated as of July 30, 2018, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 31, 2018).
Exhibit 10.2	Amended and Restated Credit Agreement dated as of July 30, 2018, among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 31, 2018).
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002.
Exhibit 95	Mine Safety and Health Administration Safety Data.
Exhibit 101	Financial Statements for XBRL Format.

*Previously filed as part of the filing indicated and incorporated by reference herein.

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SIGNATURES

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

BLACK HILLS CORPORATION

/s/ David R. Emery
David R. Emery, Chairman and
Chief Executive Officer

/s/ Richard W. Kinzley
Richard W. Kinzley, Senior Vice President and
Chief Financial Officer

Dated: August 7, 2018

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