BLACK HILLS CORP /SD/
Form 10-Q
November 06, 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 September 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 every Interactive Data File required to be submitted 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 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	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 November 1, 2018	
Common stock, $1.00 par value	59,974,620	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
Busch Ranch	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm.
Busch Ranch II	Busch Ranch II wind project will be a 60 MW wind farm near Pueblo, Colorado, built by Black Hills Electric Generation to provide wind energy to Colorado Electric through a 25-year power purchase agreement.
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 that were formerly due 2028 prior to the successful remarketing on August 17, 2018.
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
PCA	Power Cost Adjustment
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
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas

	transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(unaudited)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
	(in thousands, except per share amounts)			
Revenue	$321,979	$335,611	$1,253,072	$1,224,968
Operating expenses:				
Fuel, purchased power and cost of natural gas sold	80,244	86,281	432,544	404,222
Operations and maintenance	115,477	109,258	350,099	335,707
Depreciation, depletion and amortization	49,046	47,109	146,345	140,636
Taxes - property, production and severance	11,905	12,408	39,181	38,866
Other operating expenses	222	996	1,993	5,996
Total operating expenses	256,894	256,052	970,162	925,427
Operating income	65,085	79,559	282,910	299,541
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(36,480)	(35,287)	(107,360)	(105,417)
Allowance for funds used during construction - borrowed	701	753	1,345	2,061
Capitalized interest	100	64	177	197
Interest income	382	402	1,012	700
Allowance for funds used during construction - equity	193	696	503	1,982
Other income (expense), net	(703)	189	(2,426)	(6)
Total other income (expense), net	(35,807)	(33,183)	(106,749)	(100,483)
Income before income taxes	29,278	46,376	176,161	199,058
Income tax benefit (expense)	(7,477)	(13,478)	11,784	(58,518)
Income from continuing operations	21,801	32,898	187,945	140,540
(Loss) from discontinued operations, net of tax	(857)	(1,300)	(5,627)	(3,485)
Net income	20,944	31,598	182,318	137,055
Net income attributable to noncontrolling interest	(3,994)	(3,935)	(10,447)	(10,674)
Net income available for common stock	$16,950	$27,663	$171,871	$126,381
Amounts attributable to common shareholders:				
Net income from continuing operations	$17,807	$28,963	$177,498	$129,866
Net (loss) from discontinued operations	(857)	(1,300)	(5,627)	(3,485)
Net income available for common stock	$16,950	$27,663	$171,871	$126,381
Earnings per share of common stock:				
Earnings (loss) per share, Basic -				
Income from continuing operations, per share	$0.33	$0.54	$3.33	$2.44
(Loss) from discontinued operations, per share	(0.02)	(0.02)	(0.10)	(0.06)

Earnings per share, Basic [a]	$0.32	$0.52	$3.22	$2.38
Earnings (loss) per share, Diluted -				
Income from continuing operations, per share	$0.32	$0.52	$3.26	$2.35
(Loss) from discontinued operations, per share	(0.02)	(0.02)	(0.10)	(0.06)
Earnings per share, Diluted [a]	$0.31	$0.50	$3.15	$2.29
Weighted average common shares outstanding:				
Basic	53,364	53,243	53,346	53,208
Diluted	54,819	55,432	54,508	55,254
Dividends declared per share of common stock	$0.475	$0.445	$1.425	$1.335

(a) EPS may not sum due to rounding.

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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(in thousands)			
Net income	$20,944	$31,598	$182,318	$137,055
Other comprehensive income (loss), net of tax:				
Reclassification adjustments of benefit plan liability - prior service cost (net of tax (expense) benefit of $10 and $17 for the three months ended September 30, 2018 and 2017 and $29 and $52 for the nine months ended September 30, 2018 and 2017, respectively)	(34)	(32)	(104)	(94)
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax (expense) benefit of $(138) and $(145) for the three months ended September 30, 2018 and 2017 and $(409) and $(445) for the nine months ended September 30, 2018 and 2017, respectively)	483	269	1,456	797
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 September 30, 2018 and 2017 and $(456) and $(779) for the nine months ended September 30, 2018 and 2017, respectively)	560	464	1,682	1,449
Net unrealized gains (losses) on commodity derivatives (net of tax (expense) benefit of $0 and $94 for the three months ended September 30, 2018 and 2017 and $51 and $(442) for the nine months ended September 30, 2018 and 2017, respectively)	30	(160)	(168)	755
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax (expense) benefit of $3 and $95 for the three months ended September 30, 2018 and 2017 and $(187) and $344 for the nine months ended September 30, 2018 and 2017, respectively)	21	(166)	615	(590)
Other comprehensive income, net of tax	1,060	375	3,481	2,317
Comprehensive income	22,004	31,973	185,799	139,372
Less: comprehensive income attributable to noncontrolling interest	(3,994)	(3,935)	(10,447)	(10,674)
Comprehensive income available for common stock	$18,010	$28,038	$175,352	$128,698

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 September 30, 2018	December 31, 2017	September 30, 2017
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$10,001	$15,420	$13,449
Restricted cash	3,241	2,820	2,683
Accounts receivable, net	152,796	248,330	150,325
Materials, supplies and fuel	122,618	113,283	122,866
Derivative assets, current	1,392	304	433
Income tax receivable, net	11,025	—	—
Regulatory assets, current	48,302	81,016	61,023
Other current assets	32,691	25,367	25,586
Current assets held for sale	2,854	84,242	8,653
Total current assets	384,920	570,782	385,018
Investments	41,202	13,090	12,947
Property, plant and equipment	5,819,000	5,567,518	5,499,557
Less: accumulated depreciation and depletion	(1,118,783)	(1,026,088)	(1,000,875)
Total property, plant and equipment, net	4,700,217	4,541,430	4,498,682
Other assets:			
Goodwill	1,299,454	1,299,454	1,299,454
Intangible assets, net	6,954	7,559	7,765
Regulatory assets, non-current	212,048	216,438	239,571
Other assets, non-current	17,143	10,149	11,626
Noncurrent assets held for sale	—	—	108,685
Total other assets, non-current	1,535,599	1,533,600	1,667,101
TOTAL ASSETS	$6,661,938	$6,658,902	$6,563,748

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		
	September 30, 2018	December 31, 2017	September 30, 2017
	(in thousands, except share amounts)		
LIABILITIES AND TOTAL EQUITY			
Current liabilities:			
Accounts payable	$115,900	$160,887	$94,790
Accrued liabilities	201,353	219,462	206,779
Derivative liabilities, current	1,154	2,081	1,458
Accrued income taxes, net	—	1,022	5,587
Regulatory liabilities, current	41,442	6,832	7,042
Notes payable	112,100	211,300	225,170
Current maturities of long-term debt	255,743	5,743	5,743
Current liabilities held for sale	2,538	41,774	7,701
Total current liabilities	730,230	649,101	554,270
Long-term debt	2,951,389	3,109,400	3,109,864
Deferred credits and other liabilities:			
Deferred income tax liabilities, net	292,753	336,520	618,315
Regulatory liabilities, non-current	508,846	478,294	198,189
Benefit plan liabilities	151,613	159,646	149,803
Other deferred credits and other liabilities	105,928	105,735	113,996
Non-current liabilities held for sale	—	—	23,329
Total deferred credits and other liabilities	1,059,140	1,080,195	1,103,632
Commitments and contingencies (See Notes 9, 11, 16, 17)			
Equity:			
Stockholders' equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 53,661,863; 53,579,986; and 53,524,529 shares, respectively	53,662	53,580	53,525
Additional paid-in capital	1,157,214	1,150,285	1,147,922
Retained earnings	644,154	548,617	516,371
Treasury stock, at cost – 72,915; 39,064; and 41,457 shares, respectively	(4,072)	(2,306)	(2,448)
Accumulated other comprehensive income (loss)	(37,703)	(41,202)	(32,566)
Total stockholders' equity	1,813,255	1,708,974	1,682,804
Noncontrolling interest	107,924	111,232	113,178
Total equity	1,921,179	1,820,206	1,795,982
TOTAL LIABILITIES AND TOTAL EQUITY	$6,661,938	$6,658,902	$6,563,748

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)	Nine Months Ended September 30,	
	2018	2017
Operating activities:	(in thousands)	
Net income	$182,318	$137,055
Loss from discontinued operations, net of tax	5,627	3,485
Income from continuing operations	187,945	140,540
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	146,345	140,636
Deferred financing cost amortization	5,682	6,212
Stock compensation	7,544	7,594
Deferred income taxes	(14,396)	65,536
Employee benefit plans	10,641	8,470
Other adjustments, net	7,668	(3,549)
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	(8,380)	(19,511)
Accounts receivable, unbilled revenues and other operating assets	72,061	103,963
Accounts payable and other operating liabilities	(86,604)	(112,288)
Regulatory assets - current	41,655	1,287
Regulatory liabilities - current	21,416	(4,328)
Contributions to defined benefit pension plans	(12,700)	(27,700)
Other operating activities, net	2,007	(1,410)
Net cash provided by operating activities of continuing operations	380,884	305,452
Net cash provided by (used in) operating activities of discontinued operations	(2,162)	13,978
Net cash provided by operating activities	378,722	319,430
Investing activities:		
Property, plant and equipment additions	(278,132)	(238,840)
Purchase of investment	(24,429)	—
Other investing activities	2,766	160
Net cash provided by (used in) investing activities of continuing operations	(299,795)	(238,680)
Net cash provided by (used in) investing activities of discontinued operations	18,024	(17,298)
Net cash provided by (used in) investing activities	(281,771)	(255,978)
Financing activities:		
Dividends paid on common stock	(76,309)	(71,334)
Common stock issued	1,079	3,562
Net (payments) borrowings of short-term debt	(99,200)	128,570
Long-term debt - issuances	700,000	—
Long-term debt - repayments	(603,307)	(104,307)
Distributions to noncontrolling interest	(13,755)	(12,884)
Other financing activities	(10,457)	(6,719)
Net cash provided by (used in) financing activities	(101,949)	(63,112)
Net change in cash, cash equivalents and restricted cash	(4,998)	340
Cash, cash equivalents and restricted cash at beginning of period	18,240	15,792
Cash, cash equivalents and restricted cash at end of period	$13,242	$16,132

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 September 30, 2018, we have sold nearly all of our oil and gas assets and we closed our oil and gas office in August. Transaction closing for the last few assets and final accounting are expected within the fourth quarter. 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 September 30, 2018, December 31, 2017, and September 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 nine months ended September 30, 2018 and September 30, 2017, and our financial condition as of September 30, 2018, December 31, 2017, and September 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. At this time, we do not believe the implementation of this standard will have a material impact on our financial position, results of operations or cash flows. We continue to develop our process of identifying and categorizing our lease contracts and evaluating our current business processes relating to leases. We have selected, configured, and tested a new lease software solution and will be entering lease data into the new system in preparation for the January 1, 2019 standard adoption. 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 requires 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 nine months ended September 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 nine months ended September 30, 2018. Sales tax and other similar taxes are excluded from revenues.

Three Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:	(in thousands)					
Retail	$157,049	$88,559	$ —	$16,751	$ (7,941)	$254,418
Transportation	—	30,079	—	—	(267)	29,812
Wholesale	8,255	—	14,485	—	(13,047)	9,693
Market - off-system sales	9,059	140	—	—	(1,349)	7,850
Transmission/Other	10,196	11,887	—	—	(3,693)	18,390
Revenue from contracts with customers	184,559	130,665	14,485	16,751	(26,297)	320,163
Other revenues	231	1,011	9,118	550	(9,094)	1,816
Total revenues	$184,790	$131,676	$ 23,603	$17,301	$ (35,391)	$321,979
Timing of revenue recognition:						
Services transferred at a point in time	$—	$—	$ —	$16,751	$ (7,941)	$8,810
Services transferred over time	184,559	130,665	14,485	—	(18,356)	311,353
Revenue from contracts with customers	$184,559	$130,665	$ 14,485	$16,751	$ (26,297)	$320,163

Nine Months Ended September 30, 2018	Electric Utilities	Gas Utilities	Power Generation	Mining	Inter-company Revenues	Total
Customer types:	(in thousands)					
Retail	$449,482	$565,816	$ —	$49,653	$ (23,761)	$1,041,190
Transportation	—	100,760	—	—	(977)	99,783
Wholesale	25,497	—	41,161	—	(36,874)	29,784
Market - off-system sales	18,142	728	—	—	(5,531)	13,339
Transmission/Other	36,622	36,230	—	—	(10,967)	61,885
Revenue from contracts with customers	529,743	703,534	41,161	49,653	(78,110)	1,245,981
Other revenues	2,218	3,106	27,429	1,675	(27,337)	7,091
Total revenues	$531,961	$706,640	$ 68,590	$51,328	$ (105,447)	$1,253,072
Timing of revenue recognition:						
Services transferred at a point in time	$—	$—	$ —	$49,653	$ (23,761)	$25,892
Services transferred over time	529,743	703,534	41,161	—	(54,349)	1,220,089
Revenue from contracts with customers	$529,743	$703,534	$ 41,161	$49,653	$ (78,110)	$1,245,981

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, derivative revenue under ASC 815 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 have received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $6.0 million and $29 million during the three and nine months ended September 30, 2018, respectively. As of September 30, 2018, $7.9 million has been returned to customers and approximately $21 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 September 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 Utilities	$ 179,527	$ 231	$ 5,032	$ —	$ 184,790	$ 21,578
Gas Utilities	130,390	1,011	275	—	131,676	(13,277)
Power Generation (b)	1,437	348	13,048	8,770	23,603	6,691
Mining	8,809	226	7,942	324	17,301	3,572
Corporate and Other	—	—	—	—	—	(757)
Inter-company eliminations	—	—	(26,297)	(9,094)	(35,391)	—
Total	$ 320,163	$ 1,816	$ —	$ —	$ 321,979	$ 17,807

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

Three Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric Utilities	$ 181,238	$ 2,333	$ 27,324
Gas Utilities	142,821	73	(4,329)
Power Generation (b)	1,810	21,117	6,155
Mining	9,742	7,751	3,477
Corporate and Other	—	—	(3,664)
Inter-company eliminations	—	(31,274)	—
Total	$ 335,611	$ —	$ 28,963

Nine Months Ended September 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 Utilities	$ 513,270	$ 2,218	$ 16,473	$ —	$ 531,961	$ 63,313
Gas Utilities (a)	702,532	3,106	1,002	—	706,640	93,182
Power Generation (b)	4,287	1,066	36,874	26,363	68,590	17,319
Mining	25,892	701	23,761	974	51,328	9,561
Corporate and Other	—	—	—	—	—	(5,877)
Inter-company eliminations	—	—	(78,110)	(27,337)	(105,447)	—
Total	$ 1,245,981	$ 7,091	$ —	$ —	$ 1,253,072	$ 177,498

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Nine Months Ended September 30, 2017	External Operating Revenue	Inter-company Operating Revenue	Net income (loss) from continuing operations
Segment:			
Electric Utilities	$518,925	$ 9,123	$68,386
Gas Utilities	674,161	90	41,409
Power Generation [(b)]	5,382	62,907	18,017
Mining	26,500	22,485	9,048
Corporate and Other [(c)]	—	—	(6,994)
Inter-company eliminations	—	(94,605)	—
Total	$1,224,968	$ —	$129,866

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(a) Net income from continuing operations available for common stock for the nine months ended September 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 nine months ended September 30, 2018 and September 30, 2017 reflects net income attributable to noncontrolling interests of $4.0 million and $10.4 million, and $3.9 million and $10.6 million, respectively.

(c) Net income (loss) from continuing operations available for common stock for the nine months ended September 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 and Other balances included in the accompanying Condensed Consolidated Balance Sheets were as follows (in thousands):

Total Assets (net of inter-company eliminations) as of:	September 30, 2018	December 31, 2017	September 30, 2017
Segment:			
Electric Utilities [(a)]	$2,853,414	$2,906,275	$2,911,919
Gas Utilities	3,433,316	3,426,466	3,288,104
Power Generation [(a)]	122,428	60,852	64,357
Mining	72,602	65,455	66,700
Corporate and Other	177,324	115,612	115,330
Discontinued operations	2,854	84,242	117,338
Total assets	$6,661,938	$6,658,902	$6,563,748

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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 as a capital lease.

(4) ACCOUNTS RECEIVABLE

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

September 30, 2018	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 43,108	$ 31,381	$ (386)	$ 74,103
Gas Utilities	48,638	24,768	(2,188)	71,218
Power Generation	1,696	—	—	1,696
Mining	3,749	—	—	3,749
Corporate	2,030	—	—	2,030
Total	$ 99,221	$ 56,149	$ (2,574)	$ 152,796

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

September 30, 2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 42,716	$ 29,762	$ (494)	$ 71,984
Gas Utilities	49,842	24,516	(1,190)	73,168
Power Generation	1,010	—	—	1,010
Mining	3,534	—	—	3,534
Corporate	629	—	—	629
Total	$ 97,731	$ 54,278	$ (1,684)	$ 150,325

(5) REGULATORY ACCOUNTING

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

	September 30, 2018	December 31, 2017	September 30, 2017
Regulatory assets			
Deferred energy and fuel cost adjustments [(a)]	$29,976	$20,187	$20,559
Deferred gas cost adjustments [(a)]	720	31,844	12,833
Gas price derivatives [(a)]	6,192	11,935	11,297
Deferred taxes on AFUDC [(b)]	7,804	7,847	15,645
Employee benefit plans [(c)]	106,734	109,235	105,671
Environmental [(a)]	972	1,031	1,051
Asset retirement obligations [(a)]	526	517	514
Loss on reacquired debt [(a)]	21,431	20,667	21,067
Renewable energy standard adjustment [(a)]	1,131	1,088	1,956
Deferred taxes on flow through accounting [(c)] [(e)]	29,342	26,978	41,900
Decommissioning costs [(b)]	11,052	13,287	13,989
Gas supply contract termination [(a)]	15,745	20,001	21,402
Other regulatory assets [(a)]	28,725	32,837	32,710
Total regulatory assets	260,350	297,454	300,594
Less current regulatory assets	(48,302)	(81,016)	(61,023)
Regulatory assets, non-current	$212,048	$216,438	$239,571
Regulatory liabilities			
Deferred energy and gas costs [(a)]	$15,980	$3,427	$3,780
Employee benefit plan costs and related deferred taxes [(c)] [(e)]	39,332	40,629	66,620
Cost of removal [(a)]	146,177	130,932	125,360
Excess deferred income taxes [(c)] [(d)]	316,625	301,553	52
TCJA revenue reserve	20,592	—	—
Other regulatory liabilities [(c)]	11,582	8,585	9,419
Total regulatory liabilities	550,288	485,126	205,231
Less current regulatory liabilities	(41,442)	(6,832)	(7,042)
Regulatory liabilities, non-current	$508,846	$478,294	$198,189

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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 September 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 or other revenue offsets.
(e) The variance to the prior periods is primarily due to the decrease in federal income tax from 35% to 21% as a result of 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 received state utility commission approvals to provide the benefits of federal tax reform to utility customers in six states. We estimated and recorded a reserve to revenue of approximately $6.0 million and $29 million during the three and nine months ended September 30, 2018, respectively. As of September 30, 2018, $7.9 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 2018 Benefit for Customers		Start Date for Customer Benefits
Arkansas	$9.7	million	October 2018
Colorado	$10.8	million	July 2018
Iowa	$2.4	million	June 2018
Kansas	$1.9	million	April 2018
Nebraska	$3.8	million	July 2018
South Dakota	$7.7	million	October 2018

In support of returning benefits to customers, the three rate review requests filed in 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

RMNG
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 the 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. New rates are inclusive of customer benefits related to the TCJA.

Wyoming Gas
On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We received 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, were effective September 1, 2018.

Arkansas Gas
On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates will generate approximately $12 million of new annual revenue. The APSC’s approval also allows Arkansas Gas to include $11 million of revenue that is currently being collected through certain rider mechanisms in the new base rates. The new revenue increase is based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

Wyoming Electric

On October 31, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric's PCA permits the recovery of costs associated with fuel, purchased electricity and other specified costs, including the portion of the company's energy that is delivered from the Wygen I PPA with Black Hills Wyoming. Wyoming Electric will provide an aggregate $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve all outstanding issues relating to its current and prior PCA filings. The settlement also stipulates the adjustment for the variable cost segment of the Wygen I PPA with Wyoming Electric will escalate by 3.0% annually through 2022, providing price certainty for Wyoming Electric and its customers. As of September 30, 2018, we have recorded a liability of $4.5 million related to the PCA.

Nebraska Gas

On June 1, 2018, Nebraska Gas Distribution filed an application with the NPSC requesting a continuation of the SSIR beyond the expiration date of October 31, 2019. On September 5, 2018, the NSPC approved continuation of the SSIR tariff to December 31, 2020. The SSIR provides approximately $6.0 million of revenue annually on investments made prior to January 1, 2018, with investments after that date to be recovered through other methods. If a base rate review is filed prior to expiration of the rider, that rate request will include the remaining investment to be recovered.

Kansas Gas

On June 19, 2018, Kansas Gas received approval from the Kansas Corporation Commission to double annual eligible investments up to $8.0 million for safety related integrity investments under the Gas System Reliability rider.

(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:

	September 30, 2018	December 31, 2017	September 30, 2017
Materials and supplies	$ 73,777	$ 69,732	$ 70,284
Fuel - Electric Utilities	2,750	2,962	2,993
Natural gas in storage held for distribution	46,091	40,589	49,589
Total materials, supplies and fuel	$ 122,618	$ 113,283	$ 122,866

(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 September 30, 2018.

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

	September 30, 2018	December 31, 2017	September 30, 2017
Cost method investment	$ 28,134	$ —	$ —
Cash surrender value of life insurance contracts	13,068	13,090	12,947
Total investments	$ 41,202	$ 13,090	$ 12,947

(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 September 30,	Nine Months Ended September 30,

	2018	2017	2018	2017
Net income available for common stock	$16,950	$27,663	$171,871	$126,381
Weighted average shares - basic	53,364	53,243	53,346	53,208
Dilutive effect of:				
Equity Units [(a)]	1,344	2,015	1,060	1,872
Equity compensation	111	174	102	174
Weighted average shares - diluted	54,819	55,432	54,508	55,254

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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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Equity compensation	12	—	15	—
Anti-dilutive shares	12	—	15	—

(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:

	September 30, 2018		December 31, 2017		September 30, 2017	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$—	$15,203	$—	$26,848	$—	$25,391
CP Program	112,100	—	211,300	—	225,170	—
Total	$112,100	$15,203	$211,300	$26,848	$225,170	$25,391

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 0.125%, 1.125%, and 1.125%, respectively, at September 30, 2018. Based on our credit ratings, a 0.175% commitment fee was charged on the unused amount at September 30, 2018. Margins and the commitment fee rate decreased in August 2018 due to our upgraded credit rating from S&P.

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 nine months ended September 30, 2018 were $99 million and our notes outstanding as of September 30, 2018 were $112 million. As of September 30, 2018, the weighted average interest rate on CP Program borrowings was 2.42%.

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 September 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 September 30, 2018	Covenant Requirement
Consolidated Indebtedness to Capitalization Ratio	61.4%	Less than 65%

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

Current Maturities

As of September 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 August 17, 2018, we issued $400 million principal amount, 4.350% senior unsecured notes due 2033. A portion of these notes were issued in a private exchange that resulted in the retirement of all $299 million principal amount of our RSNs due 2028. The remainder of the notes were sold for cash in a public offering, with the net proceeds being used to pay down short-term debt.

The issuance of these new senior notes was the culmination of a series of transactions that also included the contractually required remarketing of such RSNs on behalf of the holders of our Equity Units, with the proceeds being deposited as collateral to secure the obligations of those holders under the purchase contracts included in the Equity Units (see subsequent event in Note 10). As a result of the remarketing, the annual interest rate on such RSNs was automatically reset to 4.579% (however, because the RSNs were then immediately retired, no interest accrued at this reset rate).

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 September 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 0.000% and 0.700%, respectively, at September 30, 2018.

(10) EQUITY

A summary of the changes in equity is as follows:

Nine Months Ended September 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)	171,871	10,447	182,318
Other comprehensive income	3,481	—	3,481
Dividends on common stock	(76,309)	—	(76,309)
Share-based compensation	4,871	—	4,871
Dividend reinvestment and stock purchase plan	220	—	220
Other stock transactions	147	—	147
Distribution to noncontrolling interest	—	(13,755)	(13,755)
Balance at September 30, 2018	$ 1,813,255	$ 107,924	$ 1,921,179

Nine Months Ended September 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)	126,381	10,567	136,948
Other comprehensive income	2,317	—	2,317
Dividends on common stock	(71,334)	—	(71,334)
Share-based compensation	5,853	—	5,853
Dividend reinvestment and stock purchase plan	2,300	—	2,300
Redeemable noncontrolling interest	(886)	—	(886)
Cumulative effect of ASU 2016-09 implementation	3,714	—	3,714
Other stock transactions	(180)	—	(180)
Distribution to noncontrolling interest	—	(12,884)	(12,884)
Balance at September 30, 2017	$ 1,682,804	$ 113,178	$ 1,795,982

At-the-Market Equity Offering Program

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 nine months ended September 30, 2018 or September 30, 2017 under the ATM equity offering program.

Subsequent Event - Equity Units Settlement

On October 29, 2018, we announced the settlement rate for the stock purchase contracts that are components of the Equity Units issued November 23, 2015. The settlement rate was based upon the minimum settlement rate, as adjusted to account for past dividends, because the average of the closing price per share of Black Hills Corporation common stock on the New York Stock Exchange for the 20 consecutive trading days ending on October 29, 2018 exceeded the threshold appreciation price. Each holder of the Equity Units on that date, following payment of $50.00 for each unit which it holds, received 1.0655 shares of Black Hills Corporation common stock for each such unit. The holders' obligations to make such payments were satisfied with proceeds generated by the successful remarketing on August 17, 2018, of the RSNs that formerly constituted a component of the Equity Units.

Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. Proceeds will be used to pay down the $250 million senior unsecured notes due January 11, 2019, with the balance used to pay down short-term debt.

As of November 1, 2018, after the Equity Units settlement, we had shares outstanding of approximately 59.97 million.

(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 October 2018 through May 2020; a portion of these 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:

	September 30, 2018		December 31, 2017		September 30, 2017	
	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]	Notional (MMBtus)	Maximum Term (months) [(a)]
Natural gas futures purchased	5,300,000	27	8,330,000	36	10,250,000	39
Natural gas options purchased, net	9,670,000	16	3,540,000	14	7,360,000	17
Natural gas basis swaps purchased	5,140,000	27	8,060,000	36	9,170,000	39
Natural gas over-the-counter swaps, net [(b)]	4,370,000	20	3,820,000	29	4,600,000	20
Natural gas physical contracts, net [(c)]	19,539,851	33	12,826,605	35	21,071,714	38

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(a) Term reflects the maximum forward period hedged.

(b) As of September 30, 2018, 2,236,000 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 September 30, 2018 prices, a $0.1 million gain 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 September 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 September 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 September 30, 2018 or December 31, 2017. At September 30, 2017, we had outstanding crude oil futures and swap contracts with notional volumes of 54,000 Bbls, crude oil option contracts with notional volumes of 9,000 Bbls and natural gas futures and swap contracts with notional volumes of 540,000 MMBtus.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income is presented below for the three and nine months ended September 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 September 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	$ (712)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(18)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (730)		$ —

Three Months Ended September 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	295	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(34)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (452)		$ —

Nine Months Ended September 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	$ (2,138)	Interest expense	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(802)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (2,940)		$ —

Nine Months Ended September 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	$ (2,228)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	954	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(20)	Fuel, purchased power and cost of natural gas sold	—
Total		$ (1,294)		$ —

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 nine months ended September 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 September 30,	
	2018	2017
	(in thousands)	
Increase (decrease) in fair value:		

Forward commodity contracts	$30	$(254)
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	712	713
Forward commodity contracts	18	(261)
Total other comprehensive income (loss) from hedging	$760	$198

	Nine Months Ended September 30,	
	2018	2017
	(in thousands)	
Increase (decrease) in fair value:		
Forward commodity contracts	$(219)	$1,197
Recognition of (gains) losses in earnings due to settlements:		
Interest rate swaps	2,138	2,228
Forward commodity contracts	802	(934)
Total other comprehensive income (loss) from hedging	$2,721	$2,491

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 nine months ended September 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 September 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	$—	$ (53)
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(96)	(322)
		$(96)	$ (375)

		Nine Months Ended September 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	$—	$ 90
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	929	(1,822)
		$929	$ (1,732)

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 $6.2 million, $12 million and $11 million at September 30, 2018, December 31, 2017 and September 30, 2017, respectively.

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(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 September 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 September 30, 2018				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 5,882	$ —	$ (4,469)	$ 1,413
Total	$ —	$ 5,882	$ —	$ (4,469)	$ 1,413
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 10,033	$ —	$ (8,777)	$ 1,256
Total	$ —	$ 10,033	$ —	$ (8,777)	$ 1,256

	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 September 30, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Utilities	$ —	$ 2,880	$ —	$ (2,448)	$ 432
Total	$ —	$ 2,880	$ —	$ (2,448)	$ 432
Liabilities:					
Commodity derivatives — Utilities	$ —	$ 12,647	$ —	$ (11,125)	$ 1,522
Total	$ —	$ 12,647	$ —	$ (11,125)	$ 1,522

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 September 30, 2018

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 142	$ —
Commodity derivatives	Other assets, non-current	21	—
Commodity derivatives	Derivative liabilities — current	—	273
Commodity derivatives	Other deferred credits and other liabilities	—	10
Total derivatives designated as hedges		$ 163	$ 283
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 1,250	$ —
Commodity derivatives	Derivative liabilities — current	—	881
Commodity derivatives	Other deferred credits and other liabilities	—	92
Total derivatives not designated as hedges		$ 1,250	$ 973

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 September 30, 2017

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 2	$ —
Commodity derivatives	Current assets held for sale	225	—
Commodity derivatives	Derivative liabilities — current	—	422
Commodity derivatives	Current liabilities held for sale	—	89
Commodity derivatives	Other deferred credits and other liabilities	—	49
Commodity derivatives	Noncurrent liabilities held for sale	—	10
Total derivatives designated as hedges		$ 227	$ 570
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$ 430	$ —
Commodity derivatives	Derivative liabilities — current	—	1,036
Commodity derivatives	Other deferred credits and other liabilities	—	15
Commodity derivatives	Noncurrent liabilities held for sale	—	15
Total derivatives not designated as hedges		$ 430	$ 1,066

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:

	September 30, 2018		December 31, 2017		September 30, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$10,001	$10,001	$15,420	$15,420	$13,449	$13,449
Restricted cash [(a)]	$3,241	$3,241	$2,820	$2,820	$2,683	$2,683
Notes payable [(b)]	$112,100	$112,100	$211,300	$211,300	$225,170	$225,170
Long-term debt, including current maturities [(c) (d)]	$3,207,132	$3,289,770	$3,115,143	$3,350,544	$3,115,607	$3,362,971

(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		Nine Months Ended	
		September 30, 2018	September 30, 2017	September 30, 2018	September 30, 2017
Gains and (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$(712)	$(713)	$(2,138)	$(2,228)
Commodity contracts	Net (loss) from discontinued operations	—	295	—	954
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(18)	(34)	(802)	(20)
		(730)	(452)	(2,940)	(1,294)
Income tax	Income tax benefit (expense)	149	154	643	435
Total reclassification adjustments related to cash flow hedges, net of tax		$(581)	$(298)	$(2,297)	$(859)
Amortization of components of defined benefit plans:					
Prior service cost	Operations and maintenance	$44	$49	$133	$146
Actuarial gain (loss)	Operations and maintenance	(621)	(414)	(1,865)	(1,242)
		(577)	(365)	(1,732)	(1,096)
Income tax	Income tax benefit (expense)	128	128	380	393
Total reclassification adjustments related to defined benefit plans, net of tax		$(449)	$(237)	$(1,352)	$(703)
Total reclassifications		$(1,030)	$(535)	$(3,649)	$(1,562)

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	—	(168)	—	(168)
Amounts reclassified from AOCI	1,682	615	1,352	3,649
Reclassifications of certain tax effects from AOCI	15	—	3	18
Ending Balance September 30, 2018	$(17,884)	$ (71)	$(19,748)	$(37,703)

	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	—	755	—	755
Amounts reclassified from AOCI	1,449	(590)	703	1,562
Ending Balance September 30, 2017	$(16,660)	$ (68)	$(15,838)	$(32,566)

(15) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Nine Months Ended	September 30, 2018	September 30, 2017
	(in thousands)	
Non-cash investing and financing activities —		
Property, plant and equipment acquired with accrued liabilities	$49,631	$33,409
Increase (decrease) in capitalized assets associated with asset retirement obligations	$155	$1,362
Cash (paid) refunded during the period —		
Interest (net of amounts capitalized)	$(104,035)	$(102,008)
Income taxes (paid) refunded	$(14,842)	$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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Service cost	$1,708	$1,759	$5,125	$5,276
Interest cost	3,867	3,880	11,602	11,640
Expected return on plan assets	(6,185)	(6,130)	(18,555)	(18,388)
Prior service cost	15	15	44	44
Net loss (gain)	2,158	1,002	6,473	3,005
Net periodic benefit cost	$1,563	$526	$4,689	$1,577

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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Service cost	$573	$575	$1,718	$1,725
Interest cost	521	533	1,563	1,600
Expected return on plan assets	(57)	(79)	(170)	(237)
Prior service cost (benefit)	(99)	(109)	(297)	(327)
Net loss (gain)	54	125	162	375
Net periodic benefit cost	$992	$1,045	$2,976	$3,136

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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Service cost	$632	$612	$1,347	$2,048
Interest cost	293	319	878	957
Prior service cost	—	—	1	1
Net loss (gain)	250	251	750	751
Net periodic benefit cost	$1,175	$1,182	$2,976	$3,757

For the three and nine months ended September 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 nine months ended September 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 September 30, 2018	Nine Months Ended September 30, 2018	Anticipated for 2018	Anticipated for 2019
Defined Benefit Pension Plan	$ 12,700	$ 12,700	$ —	$ 12,700
Non-pension Defined Benefit Postretirement Healthcare Plans	$ 1,234	$ 3,702	$ 1,234	$ 3,821
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$ 343	$ 1,029	$ 343	$ 1,623

(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 except for those described below.

Busch Ranch I

Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm. On September 20, 2018, Black Hills Electric Generation agreed to purchase AltaGas's 50% interest in Busch Ranch for $16 million. The purchase, which is subject to FERC approval, is expected to be finalized by the end of 2018.

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 September 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 September 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 September 30, 2018, we have sold nearly all of our oil and gas assets and we closed our oil and gas office in August. Transaction closing for the last few assets and final accounting are expected within the fourth quarter. We expect to transfer any associated liabilities, and settle substantially all remaining liabilities by December 31, 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 September 30, 2018.

During the nine months ended September 30, 2018, we recorded $2.9 million of expenses comprised of royalty payments and reclamation costs related to final closing on the sale of BHEP assets.

Total assets and liabilities of the Oil and Gas segment at September 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 the end of 2018. Held for sale assets and liabilities at September 30, 2017 are classified as current and non-current (in thousands):

	September 30, 2018	December 31, 2017	September 30, 2017
Other current assets	$ 75	$ 10,360	$ 8,457
Derivative assets, current and noncurrent	—	—	225
Deferred income tax assets, noncurrent, net	—	16,966	12,571
Property, plant and equipment, net	2,779	56,916	96,085
Other current liabilities	(2,138)	(18,966)	(7,597)
Derivative liabilities, current and noncurrent	—	—	(114)
Deferred income tax liabilities, noncurrent, net	(400)	—	—
Other noncurrent liabilities	—	(22,808)	(23,319)
Net assets (liabilities)	$ 316	$ 42,468	$ 86,308

At September 30, 2018, December 31, 2017 and September 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.

The Oil and Gas segment’s other current liabilities at September 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 September 30, 2017 consisted primarily of accrued royalties, payroll and property taxes. Other noncurrent liabilities at December 31, 2017 and September 30, 2017 consisted primarily of asset retirement obligations relating to plugging and abandonment of oil and gas wells.

(19) INCOME TAXES

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

	Three Months Ended September 30,	
Tax (benefit) expense	2018	2017
Federal statutory rate	21.0 %	35.0 %
State income tax (net of federal tax effect) [(a)]	(6.3)	(3.4)
Percentage depletion in excess of cost	(0.5)	(0.9)
Accounting for uncertain tax positions adjustment	—	(0.6)
Noncontrolling interest [(b)]	(1.3)	(3.0)
Tax credits [(c)]	(5.3)	(1.6)
Effective tax rate adjustment [(d)]	—	3.9
Flow-through adjustments	(1.5)	(1.6)
TCJA change in estimate [(e)]	17.6	—
AFUDC equity	(0.1)	—
Other tax differences	1.9	1.3
	25.5 %	29.1 %

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(a) Adjustment to the deferred state rate and reduced state tax expense for the quarter.

(b) The adjustment reflects the noncontrolling interest attributable to the sale in April 2016 of 49.9% of the membership interests of COIPP LLC.

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

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

(e) 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 September 30, 2018, we recorded an additional $5.3 million of tax expense associated with changes in the prior estimated impacts of tax reform on deferred income taxes.

	Nine Months Ended September 30,	
Tax (benefit) expense	2018	2017
Federal statutory rate	21.0 %	35.0 %
State income tax (net of federal tax effect)	0.4	0.3
Percentage depletion in excess of cost	(0.4)	(0.6)
Accounting for uncertain tax positions adjustment	—	(0.2)
Noncontrolling interest	(1.1)	(1.9)
IRC 172(f) carryback claim [(a)]	—	(1.0)
Tax credits [(b)]	(2.6)	(1.6)
Effective tax rate adjustment	—	0.3
Flow-through adjustments	(0.8)	(1.2)
TCJA change in estimate [(c)]	4.3	—
AFUDC equity	(0.1)	—
Jurisdictional simplification project [(d)]	(28.1)	—
Other tax differences	0.7	0.3
	(6.7)%	29.4 %

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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 tax credits are due to the production tax credits for the Peak View wind farm.

(c) 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 nine months ended September 30, 2018, we recorded an additional $7.5 million of tax expense associated with changes in the prior estimated impacts of tax reform on deferred income taxes.

(d) Tax benefit from legal restructuring associated with amortizable goodwill as part of 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, $49 million of deferred income tax assets, 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 - Deferred Taxes

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, which reflected our provisional estimate of the impact of the TCJA, under SEC Staff Accounting Bulletin No. 118. 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 state regulatory commissions.

In addition to current year utility revenue reserves as disclosed in Note 5, we recorded additional changes in estimates of the provisional amounts recorded at December 31, 2017, primarily related to bonus depreciation and other plant and property items, after filing our 2017 tax returns which increased tax expense by $5.3 million for the three months, and decreased tax benefit by $7.5 million for the nine months ended September 30, 2018. We will continue to evaluate subsequent regulations, clarifications and interpretations of the assumptions made, which could change our estimates related to the TCJA, which we expect to finalize in the fourth quarter.

(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:

	September 30, 2018	December 31, 2017	September 30, 2017
Accrued employee compensation, benefits and withholdings	$ 57,600	$ 52,467	$ 52,841
Accrued property taxes	37,660	42,029	36,993
Customer deposits and prepayments	42,002	44,420	41,012
Accrued interest and contract adjustment payments	31,139	33,822	30,977
CIAC current portion	1,552	1,552	1,575
Other (none of which is individually significant)	31,400	45,172	43,381
Total accrued liabilities	$ 201,353	$ 219,462	$ 206,779

(21) SUBSEQUENT EVENTS

There are no subsequent events, other than those disclosed in Note 5 and Note 10.

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 nine months ended September 30, 2018 and 2017, and our financial condition as of September 30, 2018, December 31, 2017 and September 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 66.

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 September 30, 2018 Compared to Three Months Ended September 30, 2017. Net income from continuing operations available for common stock for the three months ended September 30, 2018 was $18 million, or $0.32 per diluted share, compared to $29 million, or $0.52 per diluted share, reported for the same period in 2017. The variance to the prior year included the following:

- Electric Utilities' earnings decreased $5.7 million primarily due a settlement agreement with the WPSC which decreased gross margins by $3.4 million, unfavorable summer weather compared to prior year, higher operating expenses driven by outside services and employee costs and $2.8 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes;
- Gas Utilities' earnings decreased $8.9 million primarily due to unfavorable weather compared to prior year, higher operating expenses driven by employee costs and outside services and $2.6 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes;
- Power Generation's earnings increased $0.5 million primarily due to the reduction in the federal tax rate from 35% to 21% from the TCJA; and
- Corporate and Other expenses decreased $2.9 million due to lower interest expense and higher prior year operating costs previously allocated to our Oil and Gas segment which were not reclassified to discontinued operations, largely allocated to operating segments in 2018.

Net income available for common stock for the three months ended September 30, 2018 was $17 million, or $0.31 per diluted share, compared to $28 million, or $0.50 per diluted share reported for the same period in 2017. (Loss) from discontinued operations for the three months ended September 30, 2018 was $(0.9) million, or $(0.02) per diluted share compared to $(1.3) million or $(0.02) per diluted share reported for the same period in 2017.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Net income from continuing operations available for common stock for the nine months ended September 30, 2018 was $177 million, or $3.26 per diluted share, compared to $130 million, or $2.35 per diluted share, reported for the same period in 2017. The variance to the prior year included the following:

- Gas Utilities' earnings increased $52 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, partially offset by an increase in operating expenses;
- Electric Utilities' earnings decreased $5.1 million due primarily to a settlement agreement with the WPSC which decreased gross margins by $3.7 million; other variances to the prior year were due to higher operating expenses driven by outside services and employee costs and $3.2 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes, partially offset by higher rider revenues from recent transmission investments, higher power marketing and wholesale margins, and favorable weather;
- Power Generation's earnings decreased $0.7 million primarily due to higher operating expenses;
- Mining earnings increased $0.5 million primarily due to higher coal sales from increased price per ton sold, partially offset by higher operating expenses and tax expense.
- Corporate and other expenses decreased $1.1 million primarily due to higher tax benefits recognized in the prior year and higher prior year operating costs previously allocated to our Oil and Gas segment which were not reclassified to discontinued operations, largely allocated to operating segments in 2018.

Net income available for common stock for the nine months ended September 30, 2018 was $172 million, or $3.15 per diluted share, compared to $126 million, or $2.29 per diluted share reported for the same period in 2017. (Loss) from discontinued operations for the nine months ended September 30, 2018 was $(5.6) million, or $(0.10) per diluted share compared to $(3.5) million or $(0.06) 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 September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
Revenue						
Revenue	$357,370	$366,885	$(9,515)	$1,358,519	$1,319,573	$38,946
Inter-company eliminations	(35,391)	(31,274)	(4,117)	(105,447)	(94,605)	(10,842)
	$321,979	$335,611	$(13,632)	$1,253,072	$1,224,968	$28,104
Net income (loss) from continuing operations available for common stock						
Electric Utilities [(b)]	$21,578	$27,324	$(5,746)	$63,313	$68,386	$(5,073)
Gas Utilities [(a)] [(b)]	(13,277)	(4,329)	(8,948)	93,182	41,409	51,773
Power Generation [(b)]	6,691	6,155	536	17,319	18,017	(698)
Mining [(b)]	3,572	3,477	95	9,561	9,048	513
	18,564	32,627	(14,063)	183,375	136,860	46,515
Corporate and Other [(b)]	(757)	(3,664)	2,907	(5,877)	(6,994)	1,117
Net income from continuing operations	17,807	28,963	(11,156)	177,498	129,866	47,632
(Loss) from discontinued operations, net of tax	(857)	(1,300)	443	(5,627)	(3,485)	(2,142)
Net income available for common stock	$16,950	$27,663	$(10,713)	$171,871	$126,381	$45,490

(a) Net income (loss) from continuing operations for the nine months ended September 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 three and nine months ended September 30, 2018 included approximately $5.3 million and $7.5 million of income tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes. The impact to our operating segments and Corporate and Other for the three and nine months ended September 30, 2018 was: Electric Utilities $2.8 million and $3.2 million; Gas Utilities $2.6 million and $2.6 million, Mining ($0.0) million and $0.5 million; Power Generation ($0.0) million and $0.7 million; and Corporate and Other ($0.1) million and $0.6 million, respectively.

Overview of Business Segments and Corporate Activity

Electric Utilities Segment

- On October 31, Wyoming Electric received approval from the WPSC for a comprehensive, multi-year settlement regarding its PCA Application filed earlier in 2018. Wyoming Electric will provide a total of $7.0 million in customer credits through the PCA mechanism in 2018, 2019 and 2020 to resolve several years of disputed issues related to PCA dockets before the commission. The settlement also stipulates that the adjustment for the variable cost segment of the Wygen I Power Purchase Agreement with Wyoming Electric (an affiliate company) will escalate by 3% annually through 2022.

- On October 3, 2018, Colorado Electric set a new winter peak load of 313 MW, exceeding the previous summer peak of 310 MW set in February 2011.

- Cooling degree days for the three and nine months ended September 30, 2018 were 9% higher and 29% higher than the 30-year average (normal) compared to 15% higher than normal for the same periods in 2017.

Heating degree days for the three and nine months ended September 30, 2018 were 20% lower and 5% higher than normal compared to 8% 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 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.

- On April 25, 2018, Colorado Electric received approval from the CPUC to contract with Black Hills Electric Generation for the 60 megawatt Busch Ranch II wind project. The project is currently under construction and is expected to be in service by the end of 2019. This renewable energy will enable Colorado Electric to comply with Colorado's Renewable Energy Standard.

Gas Utilities Segment

- Rate Review updates:

- On October 5, 2018, Arkansas Gas received approval from the APSC for a general rate increase. The new rates will generate approximately $12 million of new revenue. The APSC’s approval also allows Arkansas Gas to include $11 million of revenue that is currently being collected through certain rider mechanisms in the new base rates. The new revenue increase is based on a return on equity of 9.61% and a capital structure of 49.1% equity and 50.9% debt. New rates, inclusive of customer benefits related to the TCJA, were effective October 15, 2018.

- On July 16, 2018, the WPSC reached a bench decision approving our Wyoming Gas (Northwest Wyoming) settlement and stipulation with the OCA. We received 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, were 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. New rates are inclusive of customer benefits related to the TCJA.

- 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.

- Heating degree days at the Gas Utilities for the three and nine months ended September 30, 2018 were 27% lower and comparable to the 30-year average (normal), respectively, compared to 22% 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 the Busch Ranch II wind project, which is expected to be in service by the end of 2019.

Corporate and Other

- On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015. Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of $299 million in exchange for approximately 6.372 million shares of common stock.

- On October 11, 2018, Fitch affirmed Black Hills’ credit rating at BBB+ and maintained a Stable outlook.

- On August 17, 2018, we completed a public debt offering of $400 million principal amount of 4.350% senior unsecured notes. The proceeds were used to repay the $299 million principal amount of our RSNs due 2028 and pay down short-term debt.

- On August 9, 2018, S&P upgraded Black Hills' credit rating to BBB+ with a Stable outlook and South Dakota Electric's credit rating to A.

- 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 September 30, 2018, matures on July 30, 2020.

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

Discontinued Operations

- On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of September 30, 2018, we have sold nearly all of our oil and gas assets and we closed our oil and gas office in August. Transaction closing for the last few assets and final accounting are expected within the fourth quarter. 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 September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue [a]	$184,790	$183,571	$1,219	$531,961	$528,048	$3,913
Total fuel and purchased power	72,928	68,733	4,195	204,334	199,398	4,936
Gross margin [b]	111,862	114,838	(2,976)	327,627	328,650	(1,023)
Operations and maintenance	45,307	40,204	5,103	135,501	125,302	10,199
Depreciation and amortization	24,720	23,446	1,274	73,873	69,427	4,446
Total operating expenses	70,027	63,650	6,377	209,374	194,729	14,645
Operating income	41,835	51,188	(9,353)	118,253	133,921	(15,668)
Interest expense, net	(12,923)	(12,744)	(179)	(39,423)	(39,049)	(374)
Other income (expense), net	(450)	649	(1,099)	(1,121)	1,579	(2,700)
Income tax benefit (expense)	(6,884)	(11,769)	4,885	(14,396)	(28,065)	13,669
Net income	$21,578	$27,324	$(5,746)	$63,313	$68,386	$(5,073)

(a) The three and nine months ended September 30, 2018 include Horizon Point shared facility revenues of approximately $2.8 million and $8.1 million, respectively, which are allocated to all of our operating segments as facility expenses. This shared facility agreement is new in 2018 and 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 September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Electric Utilities was $22 million for the three months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $27 million for the three months ended September 30, 2017, as a result of:

Gross margin for the three months ended September 30, 2018 decreased $3.0 million compared to the same period in the prior year as a result of:

	(in millions)
TCJA revenue reserve	$ (5.7)
Wyoming Electric PCA Stipulation	(3.4)
Weather	(0.8)
Commercial and industrial demand	(0.4)
Horizon Point shared facility revenue [b]	2.8
Power Marketing, ancillary wheeling and Tech Services	2.6
Residential customer growth	1.0
Rider recovery	0.9
Total (decrease) in Gross margin [a]	$ (3.0)

(a) Non-GAAP measure

(b) Horizon Point shared facility revenue is offset by facility expenses at our operating segments and has no impact on consolidated results.

Operations and maintenance increased primarily due to $1.2 million higher facility costs, $1.3 million higher outside services primarily from distribution and transmission line surveying expenses and $1.5 million higher employee related expenses driven primarily by labor and benefits.

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, partially offset by $2.8 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes.

Results of Operations for the Electric Utilities for the Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Electric Utilities was $63 million for the nine months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $68 million for the nine months ended September 30, 2017, as a result of:

Gross margin for the nine months ended September 30, 2018 decreased $1.0 million compared to the same period in the prior year as a result of:

	(in millions)
TCJA revenue reserve	$ (17.2)
Wyoming Electric PCA Stipulation	(3.7)
Horizon Point shared facility revenue [(b)]	8.1
Rider recovery	5.0
Weather	2.6
Power Marketing, ancillary wheeling and Tech Services	2.3
Residential customer growth	1.5
Commercial and industrial demand	0.4
Total (decrease) in Gross margin [(a)]	$ (1.0)

(a) Non-GAAP measure
(b) Horizon Point shared facility revenue is offset by facility expenses at our operating segments and has no impact on consolidated results.

Operations and maintenance increased primarily due to $2.8 million of higher vegetation management expenses, $3.6 million of shared facility costs and $1.5 million of outside service costs primarily from distribution and transmission line surveying expenses. 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, partially offset by $3.2 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes.

Operating Statistics

	Electric Revenue (in thousands)				Quantities sold (MWh)			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Residential	$58,122	$55,866	$163,979	$158,017	372,623	369,466	1,084,531	1,038,437
Commercial	65,794	68,044	192,680	195,495	550,791	557,975	1,560,911	1,547,254
Industrial	31,939	30,564	93,959	91,583	429,133	406,946	1,248,438	1,192,316
Municipal	4,582	4,958	13,389	13,934	43,972	47,389	122,953	125,065
Subtotal Retail Revenue - Electric	160,437	159,432	464,007	459,029	1,396,519	1,381,776	4,016,833	3,903,072
Contract Wholesale	8,256	8,048	25,497	22,593	221,327	185,723	677,163	537,720
Off-system/Power Marketing Wholesale	9,059	5,932	18,142	15,110	206,791	159,425	514,686	477,283
Other	7,038	10,159	24,315	31,316	—	—	—	—
Total Revenue and Energy Sold	184,790	183,571	531,961	528,048	1,824,637	1,726,924	5,208,682	4,918,075
Other Uses, Losses or Generation, net	—	—	—	—	121,478	134,595	337,939	354,572
Total Revenue and Energy	184,790	183,571	531,961	528,048	1,946,115	1,861,519	5,546,621	5,272,647
Less cost of fuel and purchased power	72,928	68,733	204,334	199,398				
Gross Margin [(a)]	$111,862	$114,838	$327,627	$328,650				

(a) Non-GAAP measure

Three Months Ended September 30,	Electric Revenue (in thousands)		Gross Margin [(a)] (in thousands)		Quantities Sold (MWh) [(b)]	
	2018	2017	2018	2017	2018	2017
South Dakota Electric	$78,067	$73,939	$52,860	$51,096	874,962	835,285
Wyoming Electric	38,671	40,670	18,843	22,990	461,074	434,945
Colorado Electric	68,052	68,962	40,159	40,752	610,079	591,289
Total Electric Revenue, Gross Margin, and Quantities Sold	$184,790	$183,571	$111,862	$114,838	1,946,115	1,861,519

(a) Non-GAAP measure

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

Nine Months Ended September 30,	Electric Revenue (in thousands)		Gross Margin [(a)] (in thousands)		Quantities Sold (MWh) [(b)]	
	2018	2017	2018	2017	2018	2017
South Dakota Electric	$222,558	$213,785	$154,158	$149,182	2,541,082	2,399,995
Wyoming Electric	120,466	123,299	62,489	68,215	1,365,932	1,298,009
Colorado Electric	188,937	190,964	110,980	111,253	1,639,607	1,574,643
Total Electric Revenue, Gross Margin, and Quantities Sold	$531,961	$528,048	$327,627	$328,650	5,546,621	5,272,647

(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.

Quantities Generated and Purchased (MWh)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Coal-fired	608,417	625,590	1,772,750	1,663,935
Natural Gas and Oil	199,351	156,465	345,978	249,065
Wind	54,450	38,773	196,932	167,429
Total Generated	862,218	820,828	2,315,660	2,080,429
Purchased	1,083,897	1,040,691	3,230,961	3,192,218
Total Generated and Purchased	1,946,115	1,861,519	5,546,621	5,272,647

Quantities Generated and Purchased (MWh)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Generated:				
South Dakota Electric	469,680	478,232	1,293,713	1,177,131
Wyoming Electric	229,262	227,391	633,696	601,780
Colorado Electric	163,276	115,205	388,251	301,518
Total Generated	862,218	820,828	2,315,660	2,080,429
Purchased:				
South Dakota Electric	405,282	357,053	1,247,369	1,222,864
Wyoming Electric	231,812	207,554	732,236	696,229
Colorado Electric	446,803	476,084	1,251,356	1,273,125
Total Purchased	1,083,897	1,040,691	3,230,961	3,192,218
Total Generated and Purchased	1,946,115	1,861,519	5,546,621	5,272,647

Degree Days	Three Months Ended September 30, 2018 Actual	Variance from 30-Year Average	Actual Variance to Prior Year	2017 Actual	Variance from 30-Year Average
Heating Degree Days:					
South Dakota Electric	236	5 %	17%	202	(10)%
Wyoming Electric	248	(19)%	(15)%	292	(4)%
Colorado Electric	35	(64)%	(60)%	87	(11)%
Combined [(a)]	147	(20)%	(13)%	168	(8)%
Cooling Degree Days:					
South Dakota Electric	356	(33)%	(40)%	595	11 %
Wyoming Electric	328	10 %	(15)%	388	30 %
Colorado Electric	910	33 %	16%	784	14 %
Combined [(a)]	603	9 %	(6)%	640	15 %

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

Degree Days	Nine Months Ended September 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	4,972	11 %	17%	4,242	(5)%
Wyoming Electric	4,285	(9)%	2%	4,186	(11)%
Colorado Electric	2,901	9 %	5%	2,773	(17)%
Combined [(a)]	3,888	5 %	9%	3,559	(11)%
Cooling Degree Days:					
South Dakota Electric	488	(23)%	(31)%	709	12 %
Wyoming Electric	430	24 %	—%	429	23 %
Colorado Electric	1,404	57 %	37%	1,027	15 %
Combined [(a)]	895	29 %	12%	798	15 %

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

Electric Utilities Power Plant Availability	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Coal-fired plants [(a)]	95.7%	98.3%	94.0%	88.1%
Natural gas-fired plants and Other plants	97.0%	94.6%	97.2%	95.8%
Wind	96.9%	91.0%	96.9%	92.0%
Total availability	96.6%	95.5%	96.1%	93.0%
Wind capacity factor	33.1%	23.6%	41.8%	34.3%

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

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.

Gas Utilities

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue:						
Natural gas — regulated	$117,070	$123,210	$(6,140)	$648,550	$602,745	$45,805
Other — non-regulated services[a]	14,606	19,684	(5,078)	58,090	71,506	(13,416)
Total revenue	131,676	142,894	(11,218)	706,640	674,251	32,389
Cost of sales:						
Natural gas — regulated	30,612	33,376	(2,764)	298,149	255,410	42,739
Other — non-regulated services[a]	5,514	11,917	(6,403)	15,716	33,615	(17,899)
Total cost of sales	36,126	45,293	(9,167)	313,865	289,025	24,840
Gross margin [b]	95,550	97,601	(2,051)	392,775	385,226	7,549
Operations and maintenance	69,746	65,390	4,356	212,319	201,105	11,214
Depreciation and amortization	21,564	20,937	627	64,288	62,658	1,630
Total operating expenses	91,310	86,327	4,983	276,607	263,763	12,844
Operating income	4,240	11,274	(7,034)	116,168	121,463	(5,295)
Interest expense, net	(20,433)	(19,527)	(906)	(59,456)	(58,919)	(537)
Other income (expense), net	(478)	(294)	(184)	(1,239)	(342)	(897)
Income tax benefit (expense)	3,394	4,218	(824)	37,709	(20,686)	58,395
Net income (loss)	(13,277)	(4,329)	(8,948)	93,182	41,516	51,666
Net (income) loss attributable to noncontrolling interest	—	—	—	—	(107)	107
Net income (loss) available for common stock	$(13,277)	$(4,329)	$(8,948)	$93,182	$41,409	$51,773

(a) The three and nine months ended September 30, 2018 include certain non-utility 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 September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net (loss) from continuing operations available for common stock for the Gas Utilities was $(13.3) million for the three months ended September 30, 2018, compared to Net loss from continuing operations available for common stock of $(4.3) million for the three months ended September 30, 2017, as a result of:

Gross margin for the three months ended September 30, 2018 decreased $2.1 million compared to the same period in the prior year as a result of:

	(in millions)
Weather	$ (2.3)
TCJA revenue reserve	(2.2)
Rate review and rider recovery	(0.3)
Non-utility - Tech Services and appliance repair	1.2
Customer growth - distribution	0.8
Mark-to-market gains on non-utility natural gas commodity contracts	0.4
Other	0.3
Total increase (decrease) in Gross margin [(a)]	$ (2.1)

(a) Non-GAAP measure

Operations and maintenance increased primarily due to $1.4 million higher facility costs, higher bad debt expense of approximately $0.5 million related to increased year-to-date revenues, $1.3 million of higher outside services primarily from line locating services and $0.3 million higher employee costs driven primarily by increased headcount.

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

Interest expense, net increased due to higher corporate allocations from financing activities compared 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) decreased from the prior year due to 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 partially offset by $2.6 million of tax expense associated with changes in the prior estimated impact of tax reform on deferred income taxes.

Results of Operations for the Gas Utilities for the Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Gas Utilities was $93 million for the nine months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $42 million for the nine months ended September 30, 2017, as a result of:

Gross margin for the nine months ended September 30, 2018 increased $7.5 million compared to the same period in the prior year as a result of:

	(in millions)
Weather	$ 7.6
Customer growth - distribution	3.6
Mark-to-market gains on non-utility natural gas commodity contracts	2.9
Rate review and rider recovery	2.8
Natural gas volumes sold	1.9
Transportation and Transmission	0.9
Non-utility - Tech Services and appliance repair	0.8
Other	0.5
TCJA revenue reserve	(13.5)
Total increase (decrease) in Gross margin [a]	$ 7.5

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(a) Non-GAAP measure

Operations and maintenance increased primarily due to higher employee costs of approximately $2.6 million driven by labor, benefits and increased corporate allocations, higher bad debt expense of approximately $2.6 million driven by the current year increase in revenues, $1.6 million of higher outside services primarily from line locating services and an increase in facility costs of $4.2 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 September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Residential	$58,221	$57,804	$383,972	$344,407	$42,598	$42,012	$192,072	$182,256
Commercial	19,639	21,366	148,675	134,156	10,880	11,097	57,890	54,931
Industrial	8,258	9,472	20,805	18,699	2,028	2,157	5,341	4,665
Other [b]	487	2,099	(6,789)	6,363	487	2,099	(6,789)	6,363
Total Distribution	86,605	90,741	546,663	503,625	55,993	57,365	248,514	248,215
Transportation and Transmission	30,465	32,469	101,887	99,120	30,465	32,470	101,887	99,121
Total Regulated	117,070	123,210	648,550	602,745	86,458	89,835	350,401	347,336
Non-regulated Services	14,606	19,684	58,090	71,506	9,092	7,766	42,374	37,890
Total Gas Revenue & Gross Margin	$131,676	$142,894	$706,640	$674,251	$95,550	$97,601	$392,775	$385,226

(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 September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
Arkansas	$18,743	$19,276	$116,226	$104,519	$13,415	$13,485	$65,803	$66,362
Colorado	22,362	21,823	125,898	120,667	15,210	16,068	66,917	69,241
Nebraska	40,553	47,577	196,307	191,288	31,264	33,290	117,925	112,418
Iowa	16,982	17,709	111,968	98,619	12,556	12,564	49,630	48,278
Kansas	18,497	20,114	81,880	77,389	11,129	11,207	40,896	39,810
Wyoming	14,539	16,395	74,361	81,769	11,976	10,987	51,604	49,117
Total Gas Revenue & Gross Margin	$131,676	$142,894	$706,640	$674,251	$95,550	$97,601	$392,775	$385,226

(a) Non-GAAP measure

	Three Months Ended September 30,		Nine Months Ended September 30,	
Gas Utilities Quantities Sold & Transported (Dth)	2018	2017	2018	2017
Residential	3,708,196	3,682,944	42,642,021	36,052,414
Commercial	2,278,304	2,445,847	20,842,996	18,111,118
Industrial	2,304,098	2,722,173	5,235,417	4,690,092

Total Distribution Quantities Sold	8,290,598	8,850,964	68,720,434	58,853,624
Transportation and Transmission	29,808,567	30,577,487	107,388,321	102,314,665
Total Quantities Sold & Transported	38,099,165	39,428,451	176,108,755	161,168,289

Gas Utilities Quantities Sold & Transported (Dth)	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
Arkansas	4,022,089	3,950,107	21,183,322	18,232,131
Colorado	2,893,029	3,111,653	19,301,834	19,156,708
Nebraska	13,831,306	14,620,729	58,223,856	52,802,084
Iowa	5,595,205	5,345,911	28,527,522	25,472,681
Kansas	6,164,821	7,270,229	23,391,905	20,975,597
Wyoming	5,592,715	5,129,822	25,480,316	24,529,088
Total Quantities Sold & Transported	38,099,165	39,428,451	176,108,755	161,168,289

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 September 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]	12	(72)%	(20)%	15	(66)%
Colorado	109	(49)%	(42)%	187	(13)%
Nebraska	101	(7)%	53%	66	(40)%
Iowa	128	(7)%	42%	90	(35)%
Kansas [a]	54	(2)%	46%	37	(32)%
Wyoming	236	(23)%	(23)%	307	1%
Combined [b]	109	(27)%	(7)%	117	(22)%

Degree Days	Nine Months Ended September 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]	2,460	(1)%	35%	1,826	(26)%
Colorado	3,548	(14)%	—%	3,541	(14)%
Nebraska	4,016	6 %	22%	3,280	(13)%
Iowa	4,460	6 %	22%	3,641	(13)%
Kansas [a]	3,032	2 %	17%	2,584	(13)%
Wyoming	4,552	(4)%	2%	4,468	(5)%
Combined [b]	4,008	— %	14%	3,521	(12)%

(a) Arkansas has a weather normalization mechanism in effect during the months of November through April for customers with residential and certain business rate schedules. Kansas Gas has a weather normalization mechanism within its residential and business rate structure. 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 mechanisms in both Arkansas and Kansas minimize weather impact on gross margins.

(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 September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue [a]	$23,603	$22,927	$ 676	$68,590	$68,289	$ 301
Operations and maintenance	7,434	7,646	(212)	25,520	24,228	1,292
Depreciation and amortization [a]	1,692	1,036	656	4,927	3,312	1,615
Total operating expense	9,126	8,682	444	30,447	27,540	2,907
Operating income	14,477	14,245	232	38,143	40,749	(2,606)
Interest expense, net	(1,264)	(724)	(540)	(3,753)	(2,015)	(1,738)
Other income (expense), net	(34)	(5)	(29)	(75)	(36)	(39)
Income tax (expense) benefit	(2,494)	(3,426)	932	(6,549)	(10,114)	3,565
Net income	10,685	10,090	595	27,766	28,584	(818)
Net income attributable to noncontrolling interest	(3,994)	(3,935)	(59)	(10,447)	(10,567)	120
Net income available for common stock	$6,691	$6,155	$ 536	$17,319	$18,017	$ (698)

(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 September 30, 2018 and September 30, 2017 was reduced by $4.0 million and $3.9 million, respectively, attributable to this noncontrolling interest.

Results of Operations for Power Generation for the Three Months Ended September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Power Generation segment was $6.7 million for the three months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $6.2 million for the same period in 2017. Revenue increased in the current year due to higher PPA prices and an increase in MWh sold. Operating expenses were comparable to the same period in the prior year reflecting lower maintenance expenses, offset by 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 Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Power Generation segment was $17 million for the nine months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $18 million for the same period in 2017. Revenue increased in the current year as a result of higher PPA prices and an increase in MWh sold. 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 associated with changes in the prior estimated impact of tax reform on deferred income taxes.

The following table summarizes MWh for our Power Generation segment:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Quantities Sold, Generated and Purchased (MWh) [(a)]				
Sold				
Black Hills Colorado IPP [(b)]	304,102	256,895	745,365	725,919
Black Hills Wyoming [(c)]	160,011	163,690	470,072	476,659
Total Sold	464,113	420,585	1,215,437	1,202,578
Generated				
Black Hills Colorado IPP [(b)]	304,102	256,895	745,365	725,919
Black Hills Wyoming [(c)]	144,476	140,081	407,324	407,775
Total Generated	448,578	396,976	1,152,689	1,133,694
Purchased				
Black Hills Colorado IPP	—	—	—	—
Black Hills Wyoming [(c)]	16,685	20,246	65,724	52,463
Total Purchased	16,685	20,246	65,724	52,463

(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 September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Contracted power plant fleet availability:				
Coal-fired plant	97.9%	97.1%	93.9%	95.8%
Natural gas-fired plants	99.3%	99.2%	99.4%	99.1%
Total availability	98.9%	98.7%	98.0%	98.3%

Mining

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Revenue	$17,301	$17,493	$ (192)	$51,328	$48,985	$2,343
Operations and maintenance	10,761	11,235	(474)	32,807	32,162	645
Depreciation, depletion and amortization	1,989	2,004	(15)	5,874	6,231	(357)
Total operating expenses	12,750	13,239	(489)	38,681	38,393	288
Operating income	4,551	4,254	297	12,647	10,592	2,055
Interest expense, net	(51)	(47)	(4)	(384)	(146)	(238)
Other income (expense), net	(70)	567	(637)	(190)	1,644	(1,834)
Income tax benefit (expense)	(858)	(1,297)	439	(2,512)	(3,042)	530
Net income	$3,572	$3,477	$ 95	$9,561	$9,048	$513

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Tons of coal sold	1,078	1,151	3,119	3,127
Cubic yards of overburden moved	2,361	2,316	6,763	6,381
Revenue per ton	$15.54	$15.20	$15.92	$15.67

Results of Operations for Mining for the Three Months Ended September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Mining segment was $3.6 million for the three months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $3.5 million for the same period in 2017. Revenue was comparable to the prior year reflecting a 6% decrease in tons sold and a 2% 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 49% of the mine's production was sold under contracts that include price adjustments based on actual mining costs, including income taxes.

Operating expenses decreased primarily due to lower royalties and production taxes on decreased revenues, and lower major maintenance expenses. 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 TCJA reduction in the federal corporate income tax rate from 35% to 21% , effective January 1, 2018.

Results of Operations for Mining for the Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net income from continuing operations available for common stock for the Mining segment was $9.6 million for the nine months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $9.0 million for the same period in 2017. Revenue increased primarily due to a 2% 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 higher overburden removal and higher fuel expenses. 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 associated with changes in the prior estimated impact of tax reform on deferred income taxes.

Corporate and Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Variance	2018	2017	Variance
	(in thousands)					
Operating (loss) [(a)]	$(16)	$(1,401)	$ 1,385	$(2,301)	$(7,183)	$ 4,882
Other income (expense):						
Interest (expense) income, net [(a)]	(626)	(1,028)	402	(1,810)	(2,331)	521
Other income (expense), net	520	(31)	551	702	(869)	1,571
Income tax benefit (expense)	(635)	(1,204)	569	(2,468)	3,389	(5,857)
Net income (loss)	$(757)	$(3,664)	$ 2,907	$(5,877)	$(6,994)	$ 1,117

(a) Includes certain general and administrative expenses and interest expenses that are not reported as discontinued operations in 2017.

Results of Operations for Corporate and Other for the Three Months Ended September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net loss from continuing operations available for common stock for Corporate and Other was $(0.8) million for the three months ended September 30, 2018, compared to Net income from continuing operations available for common stock of $(3.7) million for the three months ended September 30, 2017. The variance was driven by higher prior year operating costs previously allocated to our Oil and Gas segment in 2017, which were not reclassified to discontinued operations in 2017, and are allocated to our operating segments in 2018. Income tax benefit (expense) increased in the current year due to higher state income tax expense.

Results of Operations for Corporate and Other for the Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net loss from continuing operations available for common stock for Corporate and Other was $(5.9) million for the nine months ended September 30, 2018, compared to Net loss from continuing operations available for common stock of $(7.0) million for the nine months ended September 30, 2017. The variance to the prior year was driven by higher prior year operating costs previously allocated to our Oil and Gas segment which were not reclassified to discontinued operations in 2017, which are allocated to our operating segments in 2018 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 and current year tax expense.

Discontinued Operations

Results of Discontinued Operations for the Three Months Ended September 30, 2018 Compared to the Three Months Ended September 30, 2017: Net loss from discontinued operations was $(0.9) million for the three months ended September 30, 2018, compared to Net loss from discontinued operations of $(1.3) million for the same period in 2017. The variance to the prior year is driven by lower revenues due to 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 was recorded in the prior year under full cost accounting, which ceased November 1, 2017 due to reclassification to assets held for sale.

Results of Discontinued Operations for the Nine Months Ended September 30, 2018 Compared to the Nine Months Ended September 30, 2017: Net loss from discontinued operations was $(5.6) million for the nine months ended September 30, 2018, compared to Net loss from discontinued operations of $(3.5) million for the same period in 2017. The variance to the prior year is driven by lower revenues due to 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 amortization of the remaining book value of accounting software. Depreciation and depletion expense was recorded in the prior year under full cost accounting, which ceased November 1, 2017 due to reclassification to assets held for sale.

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 September 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. During the nine months ended September 30, 2018, we recorded approximately $16 million of additional regulatory liability associated with TJCA related items. 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 $40 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 September 30 (in thousands):

Cash provided by (used in):	2018	2017	Increase (Decrease)
Operating activities	$378,722	$319,430	$59,292
Investing activities	$(281,771)	$(255,978)	$(25,793)
Financing activities	$(101,949)	$(63,112)	$(38,837)

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

Operating Activities

Net cash provided by operating activities was $379 million for the nine months ended September 30, 2018, compared to net cash provided by operating activities of $319 million for the same period in 2017 for an increase of $59 million. The variance was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $14 million lower for the nine months ended September 30, 2018 compared to the same period in the prior year;

- Net cash inflows from changes in operating assets and liabilities were $29 million for the nine months ended September 30, 2018, compared to net cash outflows of $60 million in the same period in the prior year. This $90 million increase was primarily due to:

Cash inflows decreased by approximately $21 million primarily as a result of increases in pre-paid tax assets and lower collections of accounts receivable, partially offset by lower natural gas in storage for the nine months ended September 30, 2018 compared to the same period in the prior year;

Cash outflows decreased by approximately $26 million as a result of increases in accounts payable and accrued liabilities driven by changes in prior year accrued interest and contract payments and other working capital requirements;

Cash inflows increased by approximately $66 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 that will be refunded due to the TCJA tax rate change; and

Net cash outflows decreased by $15 million due to additional pension contributions made in the prior year.

Investing Activities

Net cash used in investing activities was $282 million for the nine months ended September 30, 2018, compared to net cash used in investing activities of $256 million for the same period in 2017 for a variance of $26 million. The variance was primarily attributable to:

- Capital expenditures of approximately $278 million for the nine months ended September 30, 2018 compared to $239 million for the same period in the prior year. Higher current year expenditures at our gas utilities, mining and power generation segments are partially offset by higher prior year 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 $35 million change in net cash provided by investing activities from discontinued operations primarily due to the sale of assets held for sale partially offset by a $24 million investment.

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Financing Activities

Net cash used in financing activities for the nine months ended September 30, 2018 was $102 million, compared to $63 million of net cash used in financing activities for the same period in 2017 for a variance of $39 million. This variance is primarily due to:

- Long–term borrowings increased due to the issuance of $400 million principal amount senior secured notes in 2018, a portion of which were issued in exchange for $299 million principal amount of our RSNs due 2028 (which were immediately retired) and a portion of which were sold to the public with $99 million of net proceeds used to pay down short-term debt;

- We amended and restated our $300 million unsecured term loan due August 2019;

- Prior year net short-term borrowings of $129 million offset by prior year long-term debt repayments of $104 million;

- $5.0 million of higher current year dividend payments; and

- Increased payments for other financing activities of approximately $3.7 million driven primarily by the July 30, 2018 and August 17, 2018 debt transactions.

Dividends

Dividends paid on our common stock totaled $76 million for the nine months ended September 30, 2018, or $0.475 per share per quarter. On October 30, 2018, our board of directors declared a quarterly dividend of $0.505 per share payable December 1, 2018, equivalent to an annual dividend of $2.02 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 September 30, 2018	CP Program Borrowings at September 30, 2018	Letters of Credit at September 30, 2018	Available Capacity at September 30, 2018
Revolving Credit Facility	July 30, 2023	$ 750	$ —	$ 112	$ 15	$ 623

The weighted average interest rate on CP Program borrowings at September 30, 2018 was 2.42%. Revolving Credit Facility and CP Program financing activity for the nine months ended September 30, 2018 was (dollars in millions):

	For the Nine Months Ended September 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)	$ 135	
Average amount outstanding - revolving credit facility (based on daily outstanding balances)	$ —	
Weighted average interest rates - commercial paper	2.16	%
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 September 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 nine months ended September 30, 2018 consisted of the following:

- Short-term borrowings from our CP Program.

- On August 17, 2018, we completed a public debt offering of $400 million principal amount, 4.350% senior unsecured notes due 2033. The proceeds were used to repay the $299 million principal amount of our RSNs due 2028 and pay down short-term debt. Through this offering, we successfully remarketed the $299 million principal amount of the existing subordinated notes, which were originally issued as a part of the Company's Equity Units on November 23, 2015. See Note 9 for more information.

- 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 September 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.

On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued

November 23, 2015. Upon settlement of all outstanding stock purchase obligations, the Company received gross proceeds of approximately $299 million in exchange for approximately 6.372 million shares of common stock. See Note 10 for more information.

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 nine months ended September 30, 2018.

Future Financing Plans

- Evaluating refinancing options for our $200 million senior notes due July 15, 2020 and the $300 million senior notes due July 30, 2020.

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 September 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 September 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 September 30, 2018:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB+	Stable

Moody's[b]	Baa2	Stable
Fitch [c]	BBB+	Stable

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(a) On August 9, 2018, S&P upgraded to BBB+ rating and revised the outlook to Stable.
(b) On December 12, 2017, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On October 11, 2018, Fitch affirmed BBB+ rating and maintained a Stable outlook.

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

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

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(a) On August 9, 2018, S&P upgraded to A rating.
(b) On July 19, 2018, Fitch affirmed A rating.

Capital Requirements

Capital Expenditures

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

	Expenditures for the Nine Months Ended September 30, 2018 [(a)]	Total 2018 Planned Expenditures [(b)]	Total 2019 Planned Expenditures	Total 2020 Planned Expenditures
Electric Utilities	$ 105,295	$ 141,000	$ 192,000	$ 165,000
Gas Utilities [(c)]	172,599	270,000	374,000	273,000
Power Generation [(d)]	4,350	46,000	60,000	9,000
Mining	11,982	19,000	8,000	7,000
Corporate and Other	8,426	12,000	17,000	21,000
	$ 302,652	$ 488,000	$ 651,000	$ 475,000

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(a) Expenditures for the nine months ended September 30, 2018 include the impact of accruals for property, plant and equipment.
(b) Includes actual capital expenditures for the nine months ended September 30, 2018.
(c) Planned capital expenditures for 2018, 2019 and 2020 increased primarily due to higher programmatic integrity spending.
(d) Planned capital expenditures for 2018 increased due to purchase of AltaGas's interest in Busch Ranch I.

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:

	September 30, 2018	December 31, 2017	September 30, 2017
Net derivative (liabilities) assets	$ (1,869)	$ (6,644)	$ (6,541)
Cash collateral offset in Derivatives	4,308	7,694	5,452
Cash collateral included in Other current assets	4,677	562	2,841
Net asset (liability) position	$ 7,116	$ 1,612	$ 1,752

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 September 30, 2018, December 31, 2017 and September 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 September 30, 2018. Based on their evaluation, they have concluded that our disclosure controls and procedures were effective at September 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 September 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 nine months ended September 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). Seventh Supplemental Indenture dated as of August 17, 2018 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on August 17, 2018).
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 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.

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: November 6, 2018