BLACK HILLS CORP /SD/
Form 10-Q
August 06, 2014

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2014

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
625 Ninth Street
Rapid City, South Dakota 57701
Registrant's telephone number (605) 721-1700
Former name, former address, and former fiscal year if changed since last report
NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes x No o

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

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

Class	Outstanding at July 31, 2014	
Common stock, $1.00 par value	44,641,421	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)
ASU	Accounting Standards Update issued by the FASB
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 Black Hills Utility Holdings, Inc., and its subsidiaries
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
Btu	British thermal unit
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation
Cheyenne Prairie	Cheyenne Prairie Generating Station currently being constructed in Cheyenne, Wyoming by Cheyenne Light and Black Hills Power. Construction is expected to be completed for this 132 megawatt facility in 2014.
Colorado Electric	Black Hills Colorado Electric Utility Company, LP (doing business as Black Hills Energy), an indirect, wholly-owned subsidiary of Black Hills Utility Holdings
Colorado IPP	Black Hills Colorado IPP, LLC a direct wholly-owned subsidiary of Black Hills Electric Generation
Cooling degree day	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.
Conflict Minerals	As defined by Dodd-Frank, conflict minerals are cassiterite, columbite-tantalite, gold and wolframite that are mined in the Democratic Republic of the Congo or surrounding countries
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CVA	Credit Valuation Adjustment
De-designated interest rate swaps	The $250 million notional amount interest rate swaps that were originally designated as cash flow hedges under accounting for derivatives and hedges but subsequently de-designated in December 2008. These swaps were settled in November 2013.
Dth	

	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EPA	United States Environmental Protection Agency
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
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.

Heating Degree Day	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.
IPP	Independent power producer
IRS	United States Internal Revenue Service
IUB	Iowa Utilities Board
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC (doing business as Black Hills Energy), a direct, wholly-owned subsidiary of Black Hills Utility Holdings
KCC	Kansas Corporation Commission
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Mcf	Thousand cubic feet
Mcfe	Thousand cubic feet equivalent.
MMBtu	Million British thermal units
Moody’s	Moody’s Investors Service, Inc.
MW	Megawatts
MWh	Megawatt-hours
NGL	Natural Gas Liquids (7 Gallons equals 1 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA’s National Weather Service.
NOL	Net Operating Loss
OTC	Over-the-counter
PPA	Power Purchase Agreement
Revolving Credit Facility	Our $500 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2019.
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
S&P	Standard and Poor’s, a division of The McGraw-Hill Companies, Inc.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands, except per share amounts)			
Revenue	$283,237	$279,826	$743,406	$660,497
Operating expenses:				
Utilities -				
Fuel, purchased power and cost of natural gas sold	101,331	99,172	331,799	267,345
Operations and maintenance	66,074	64,977	137,301	130,667
Non-regulated energy operations and maintenance	21,350	20,890	43,682	42,219
Depreciation, depletion and amortization	36,712	35,152	72,795	69,933
Taxes - property, production and severance	11,044	10,069	21,380	20,449
Other operating expenses	149	529	274	1,001
Total operating expenses	236,660	230,789	607,231	531,614
Operating income	46,577	49,037	136,175	128,883
Other income (expense):				
Interest charges -				
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts and realized settlements on interest rate swaps)	(17,886)	(23,369)	(35,746)	(47,041)
Allowance for funds used during construction - borrowed	256	411	526	484
Capitalized interest	246	272	503	538
Unrealized gain (loss) on interest rate swaps, net	—	18,793	—	26,249
Interest income	576	475	966	760
Allowance for funds used during construction - equity	293	42	531	242
Other income (expense), net	409	473	1,000	879
Total other income (expense), net	(16,106)	(2,903)	(32,220)	(17,889)
Income (loss) before earnings (loss) of unconsolidated subsidiaries and income taxes	30,471	46,134	103,955	110,994
Equity in earnings (loss) of unconsolidated subsidiaries	—	—	—	(86)
Income tax benefit (expense)	(10,651)	(15,616)	(36,017)	(37,193)
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Earnings (loss) per share of common stock:				
Earnings (loss) per share, Basic -				
Total income (loss) per share, Basic	$0.45	$0.69	$1.53	$1.67
Earnings (loss) per share, Diluted -				
Total income (loss) per share, Diluted	$0.44	$0.69	$1.52	$1.66
Weighted average common shares outstanding:				
Basic	44,399	44,172	44,365	44,113

Diluted	44,588	44,412	44,571	44,363
Dividends paid per share of common stock	$0.39	$0.38	$0.78	$0.76

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 (LOSS)

(unaudited)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Other comprehensive income (loss), net of tax:				
Fair value adjustments on derivatives designated as cash flow hedges (net of tax (expense) benefit of $1,115 and $(2,174) for the three months ended 2014 and 2013 and $2,422 and $(1,057) for the six months ended 2014 and 2013, respectively)	(1,959)	3,878	(4,216)	2,217
Reclassification adjustments for cash flow hedges settled and included in net income (loss) (net of tax (expense) benefit of $(774) and $(647) for the three months ended 2014 and 2013 and $(1,199) and $(883) for the six months ended 2014 and 2013, respectively)	1,403	1,201	2,183	1,669
Benefit plan liability adjustments - net gain (loss) (net of tax of $0 and $0 for the three months ended 2014 and 2013 and $2 and $0 for the six months ended 2014 and 2013, respectively)	—	—	(2)	—
Benefit plan liability tax adjustments - net gain (loss)	(394)	—	(394)	—
Benefit plan liability adjustments - prior service cost (net of tax of $0 and $0 for the three months ended 2014 and 2013 and $(90) and $0 for the six months ended 2014 and 2013, respectively)	—	—	164	—
Reclassification adjustments of benefit plan liability - prior service cost (net of tax of $39 and $(268) for the three months ended 2014 and 2013 and $43 and $(251) for the six months ended 2014 and 2013, respectively)	(70)	364	(79)	318
Reclassification adjustments of benefit plan liability - net gain (loss) (net of tax of $(91) and $0 for the three months ended 2014 and 2013 and $(176) and $(192) for the six months ended 2014 and 2013, respectively)	168	—	325	503
Other comprehensive income (loss), net of tax	(852)	5,443	(2,019)	4,707
Comprehensive income (loss) available for common stock	$18,968	$35,961	$65,919	$78,422

See Note 11 for additional disclosures.

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(unaudited)	As of June 30, 2014	December 31, 2013	June 30, 2013
	(in thousands)		
ASSETS			
Current assets:			
Cash and cash equivalents	$14,697	$7,841	$30,633
Restricted cash and equivalents	2	2	7,279
Accounts receivable, net	135,145	177,573	132,726
Materials, supplies and fuel	81,164	88,478	73,768
Derivative assets, current	1,737	717	903
Income tax receivable, net	1,043	1,460	146
Deferred income tax assets, net, current	23,872	18,889	38,764
Regulatory assets, current	64,735	24,451	26,258
Other current assets	21,660	25,877	27,595
Total current assets	344,055	345,288	338,072
Investments	17,096	16,697	16,566
Property, plant and equipment	4,408,291	4,259,445	4,066,502
Less: accumulated depreciation and depletion	(1,325,660)	(1,269,148)	(1,234,578)
Total property, plant and equipment, net	3,082,631	2,990,297	2,831,924
Other assets:			
Goodwill	353,396	353,396	353,396
Intangible assets, net	3,286	3,397	3,508
Regulatory assets, non-current	138,226	138,197	180,646
Other assets, non-current	31,808	27,906	22,402
Total other assets, non-current	526,716	522,896	559,952
TOTAL ASSETS	$3,970,498	$3,875,178	$3,746,514

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

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

	As of June 30, 2014	December 31, 2013	June 30, 2013
	(in thousands, except share amounts)		
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$100,098	$130,416	$88,071
Accrued liabilities	141,177	151,277	135,819
Derivative liabilities, current	3,480	3,474	69,270
Regulatory liabilities, current	828	10,727	20,550
Notes payable	132,700	82,500	100,000
Current maturities of long-term debt	275,000	—	255,507
Total current liabilities	653,283	378,394	669,217
Long-term debt, net of current maturities	1,121,950	1,396,948	958,559
Deferred credits and other liabilities:			
Deferred income tax liabilities, net, non-current	476,059	432,287	387,674
Derivative liabilities, non-current	4,251	5,614	12,384
Regulatory liabilities, non-current	119,462	109,429	129,013
Benefit plan liabilities	116,403	111,479	177,216
Other deferred credits and other liabilities	137,765	133,279	129,763
Total deferred credits and other liabilities	853,940	792,088	836,050
Commitments and contingencies (See Notes 7, 8, 13, 14 and 15)			
Stockholders' equity:			
Common stock equity —			
Common stock $1 par value; 100,000,000 shares authorized; issued 44,682,885; 44,550,239; and 44,516,472 shares, respectively	44,683	44,550	44,517
Additional paid-in capital	744,505	742,344	737,729
Retained earnings	573,379	540,244	532,810
Treasury stock, at cost – 40,951; 50,877; and 42,480 shares, respectively	(1,801)	(1,968)	(1,587)
Accumulated other comprehensive income (loss)	(19,441)	(17,422)	(30,781)
Total stockholders' equity	1,341,325	1,307,748	1,282,688
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,970,498	$3,875,178	$3,746,514

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

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BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Six Months Ended June 30,	
	2014	2013
Operating activities:	(in thousands)	
Net income (loss) available for common stock	$67,938	$73,715
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	72,795	69,933
Deferred financing cost amortization	1,107	2,188
Derivative fair value adjustments	(1,660)	4,248
Stock compensation	6,908	6,896
Unrealized (gain) loss on interest rate swaps, net	—	(26,249)
Deferred income taxes	35,514	36,607
Employee benefit plans	7,409	11,096
Other adjustments, net	1,481	8,967
Changes in certain operating assets and liabilities:		
Materials, supplies and fuel	7,314	8,940
Accounts receivable, unbilled revenues and other operating assets	(5,851)	28,377
Accounts payable and other operating liabilities	(24,978)	(26,739)
Other operating activities, net	5,858	(594)
Net cash provided by (used in) operating activities	173,835	197,385
Investing activities:		
Property, plant and equipment additions	(177,302)	(147,230)
Other investing activities	(2,994)	2,006
Net cash provided by (used in) investing activities	(180,296)	(145,224)
Financing activities:		
Dividends paid on common stock	(34,803)	(33,774)
Common stock issued	1,693	2,570
Short-term borrowings - issuances	214,100	133,300
Short-term borrowings - repayments	(163,900)	(310,300)
Long-term debt - issuances	—	275,000
Long-term debt - repayments	—	(103,786)
Other financing activities	(3,773)	—
Net cash provided by (used in) financing activities	13,317	(36,990)
Net change in cash and cash equivalents	6,856	15,171
Cash and cash equivalents, beginning of period	7,841	15,462
Cash and cash equivalents, end of period	$14,697	$30,633

See Note 12 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 2013 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 2013 Annual Report on Form 10-K filed with the SEC.

We conduct our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation, Coal Mining and Oil and Gas. Our reportable segments are based on our method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. All of our operations and assets are located within the United States.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying Condensed Consolidated Financial Statements reflects all adjustments, including accruals, which are, in the opinion of management, necessary for a fair presentation of the June 30, 2014, December 31, 2013, and June 30, 2013 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 price. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment's peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2014 and June 30, 2013, and our financial condition as of June 30, 2014, December 31, 2013, and June 30, 2013, 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.

Recently Issued and Adopted Accounting Standards

We have implemented all new accounting pronouncements that are in effect and may impact our financial statements and do not believe that there are any other new accounting pronouncements that have been issued that might have a material impact on our financial position, results of operations, or cash flows.

Revenue from Contracts with Customers, ASU 2014-09
In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. ASU 2014-09 is effective for annual and interim reporting periods beginning after December 15, 2016 and early adoption is not

permitted. We are currently assessing the impact, if any, that ASU 2014-09 will have on our financial position, results of operations, or cash flows.

(2) BUSINESS SEGMENT INFORMATION

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

Three Months Ended June 30, 2014	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$158,740	$3,144	$11,427
Gas	102,499	—	1,994
Non-regulated Energy:			
Power Generation	1,267	20,713	7,194
Coal Mining	5,583	9,068	2,016
Oil and Gas	15,148	—	(1,660)
Corporate activities	—	—	(1,151)
Inter-company eliminations	—	(32,925)	—
Total	$283,237	$—	$19,820

Three Months Ended June 30, 2013	External Operating Revenue	Inter-company Operating Revenue	Net Income (Loss)
Utilities:			
Electric	$154,338	$3,694	$10,610
Gas	105,836	—	3,192
Non-regulated Energy:			
Power Generation	1,031	19,094	5,031
Coal Mining	6,807	7,511	1,973
Oil and Gas	11,814	—	(1,964)
Corporate activities [(a)]	—	—	11,679
Inter-company eliminations	—	(30,299)	(3)
Total	$279,826	$—	$30,518

Six Months Ended June 30, 2014	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$336,835	$7,151	$26,002
Gas	361,836	—	26,692
Non-regulated Energy:			
Power Generation	2,536	41,792	15,267
Coal Mining	12,201	17,948	4,480
Oil and Gas	29,998	—	(3,682)
Corporate activities	—	—	(821)
Inter-company eliminations	—	(66,891)	—
Total	$743,406	$—	$67,938

Six Months Ended June 30, 2013	External Operating Revenues	Intercompany Operating Revenues	Net Income (Loss)
Utilities:			
Electric	$312,821	$7,841	$22,966
Gas	305,648	—	21,675
Non-regulated Energy:			
Power Generation	2,053	38,432	10,675
Coal Mining	12,817	15,084	3,038
Oil and Gas	27,158	—	(2,017)
Corporate activities [a]	—	—	17,378
Inter-company eliminations	—	(61,357)	—
Total	$660,497	$—	$73,715

(a) Corporate activities include a $12 million and a $17 million after-tax non-cash mark-to-market gain for the three and six months ended June 30, 2013, respectively on certain interest rate swaps.

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

Total Assets (net of inter-company eliminations) as of:	June 30, 2014	December 31, 2013	June 30, 2013
Utilities:			
Electric [a]	$2,603,900	$2,525,947	$2,417,952
Gas	799,365	805,617	734,337
Non-regulated Energy:			
Power Generation [a]	85,269	95,692	108,515
Coal Mining	73,701	78,825	82,553
Oil and Gas	307,837	288,366	256,855
Corporate activities	100,426	80,731	146,302
Total assets	$3,970,498	$3,875,178	$3,746,514

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

(3) ACCOUNTS RECEIVABLE

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

June 30, 2014	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$48,333	$21,716	$(622)	$69,427
Gas Utilities	43,104	9,265	(1,027)	51,342
Power Generation	1,388	—	—	1,388
Coal Mining	1,866	—	—	1,866
Oil and Gas	9,123	—	(13)	9,110
Corporate	2,012	—	—	2,012
Total	$105,826	$30,981	$(1,662)	$135,145

December 31, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$52,437	$23,823	$(666)	$75,594
Gas Utilities	49,162	41,195	(558)	89,799
Power Generation	1,722	—	—	1,722
Coal Mining	1,711	—	—	1,711
Oil and Gas	8,156	—	(13)	8,143
Corporate	604	—	—	604
Total	$113,792	$65,018	$(1,237)	$177,573

June 30, 2013	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$45,250	$24,290	$(630)	$68,910
Gas Utilities	38,749	13,192	(1,074)	50,867
Power Generation	157	—	—	157
Coal Mining	2,503	—	—	2,503
Oil and Gas	8,373	—	(19)	8,354
Corporate	1,935	—	—	1,935
Total	$96,967	$37,482	$(1,723)	$132,726

(4) REGULATORY ACCOUNTING

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

	Maximum Amortization (in years)	As of June 30, 2014	As of December 31, 2013	As of June 30, 2013
Regulatory assets				
Deferred energy and fuel cost adjustments - current [(a)(d)]	1	$29,605	$16,775	$15,951
Deferred gas cost adjustments and natural gas price derivatives [(a)(d)]	7	39,040	12,366	13,090
AFUDC [(b)]	45	12,468	12,315	12,456
Employee benefit plans [(c)]	13	65,874	67,059	115,379
Environmental [(a)]	subject to approval	1,314	1,800	1,798
Asset retirement obligations [(a)]	44	3,278	3,266	3,257
Bond issue cost [(a)]	24	3,347	3,419	3,489
Renewable energy standard adjustment [(a)]	5	14,501	14,186	14,694
Flow through accounting [(c)]	35	22,754	20,916	17,995
Other regulatory assets [(a)]	15	10,780	10,546	8,795
		$202,961	$162,648	$206,904
Regulatory liabilities				
Deferred energy and gas costs [(a)]	1	$6,490	$11,708	$22,340
Employee benefit plans [(c)]	13	34,356	34,431	60,214
Cost of removal [(a)]	44	70,841	64,970	59,461
Other regulatory liabilities [(c)]	25	8,603	9,047	7,548
		$120,290	$120,156	$149,563

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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, respectively.

(d) Our deferred energy, fuel cost, and gas cost adjustments represent the cost of electricity and gas delivered to our electric and gas utility customers that is either higher or lower than current rates and will be recovered or refunded in future rates. Increases in the current year balances as of June 30, 2014 are primarily due to higher natural gas prices driven by demand and market conditions during our peak winter heating season. Our electric and gas utilities file periodic quarterly, semi-annual, and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

(5) MATERIALS, SUPPLIES AND FUEL

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

	June 30, 2014	December 31, 2013	June 30, 2013
Materials and supplies	$51,925	$50,196	$51,334
Fuel - Electric Utilities	7,679	6,213	6,817
Natural gas in storage held for distribution	21,560	32,069	15,617

Total materials, supplies and fuel	$81,164	$88,478	$73,768

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(6) EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss) available for common stock	$19,820	$30,518	$67,938	$73,715
Weighted average shares - basic	44,399	44,172	44,365	44,113
Dilutive effect of:				
Equity compensation	189	240	206	250
Weighted average shares - diluted	44,588	44,412	44,571	44,363

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Equity compensation	81	28	63	34
Anti-dilutive shares	81	28	63	34

(7) NOTES PAYABLE AND CURRENT MATURITIES OF LONG-TERM DEBT

We had the following short-term debt outstanding in the accompanying Condensed Consolidated Balance Sheets (in thousands) as of:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit	Balance Outstanding	Letters of Credit
Revolving Credit Facility	$132,700	$20,272	$82,500	$22,100	$100,000	$43,157

Revolving Credit Facility

On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. 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 most favorable Corporate credit rating from S&P and Moody's for our unsecured 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, from May 29, 2014 through June 30, 2014; a reduction of 0.25% for each method of borrowing as compared to the previous arrangement. Borrowings under the facility are primarily Eurodollar based. A commitment fee is charged on the unused amount of the Revolving Credit Facility and was 0.175% based on our credit rating, a reduction of 0.025% compared to the prior arrangement.

Current Maturities Of Long-Term Debt

As of June 30, 2014, our Corporate term loan due June 19, 2015, for $275 million has been re-classified to Current maturities of long-term debt from Long-term debt, net of current maturities.

Debt Covenants

Our Revolving Credit Facility and our Term Loan require compliance with the following financial covenant at the end of each quarter:

	As of June 30, 2014	Covenant Requirement
Recourse Leverage Ratio	54%	Less than 65%

As of June 30, 2014, we were in compliance with this covenant.

(8) 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 2013 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 natural long position in crude oil and natural gas reserves and production; and our fuel procurement for certain of our 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 upon 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.

As of June 30, 2014, our credit exposure included a $0.5 million exposure to a non-investment grade energy marketing company. The remainder of our credit exposure was concentrated primarily among retail utility customers, investment grade rated companies, cooperative utilities and federal agencies. Our derivative and hedging activities recorded in the accompanying Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Income (Loss) and Condensed Consolidated Statements of Comprehensive Income (Loss) are detailed below and in Note 9.

Oil and Gas

We produce natural gas and crude oil through our exploration and production activities. Our natural long positions, or unhedged open positions, result in commodity price risk and variability to our cash flows.

To mitigate commodity price risk and preserve cash flows, we primarily use OTC swaps, exchange traded futures and related options to hedge portions of our crude oil and natural gas production. We elect hedge accounting on these instruments. These transactions were designated at inception as cash flow hedges, documented under accounting standards for derivatives and hedging, and initially met prospective effectiveness testing. Effectiveness of our hedging position is evaluated at least quarterly.

The derivatives were marked to fair value and were recorded as Derivative assets or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheets. The effective portion of the gain or loss on these derivatives for which we have elected cash flow hedge accounting is reported in AOCI in the accompanying Condensed Consolidated Balance Sheets and the ineffective portion, if any, is reported in Revenue in the accompanying Condensed Consolidated Statements of Income (Loss).

The contract or notional amounts, terms of our commodity derivatives, and the derivative balances for our Oil and Gas segment reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps	Crude Oil Futures, Swaps and Options	Natural Gas Futures and Swaps
Notional [(a)]	424,500	9,265,000	412,500	7,082,500	520,500	10,712,500
Maximum terms in months [(b)]	1	1	3	1	6	1
Derivative assets, current	$—	$—	$55	$—	$610	$293
Derivative assets, non-current	$—	$—	$—	$—	$—	$—
Derivative liabilities, current	$—	$—	$—	$—	$130	$276
Derivative liabilities, non-current	$—	$—	$—	$—	$—	$—

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(a) Crude oil in Bbls, natural gas in MMBtus.

(b) Refers to the term of the derivative instrument. Assets and liabilities are classified as current/non-current based on the term of the hedged transaction and the corresponding settlement of the derivative instrument.

A $3.4 million loss is included in AOCI at June 30, 2014, and would be realized over the next 12 months if market prices remained equal to June 30, 2014 prices. Future realized gains or losses fluctuate with market prices.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used for Electric Utility 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 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. 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 (Loss).

The contract or notional amounts and terms of the natural gas derivative commodity instruments held at our Utilities were as follows, as of:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)	Notional (MMBtus)	Maximum Term (months)
Natural gas futures purchased	16,240,000	78	17,930,000	84	13,330,000	77
Natural gas options purchased	3,980,000	9	3,890,000	8	2,850,000	5
Natural gas basis swaps purchased	13,415,000	66	14,785,000	60	10,650,000	66

We had the following derivative balances related to the hedges in our Utilities reflected in our Condensed Consolidated Balance Sheets as of (in thousands):

	June 30, 2014	December 31, 2013	June 30, 2013
Derivative assets, current	$1,737	$662	$—
Derivative assets, non-current	$—	$—	$—
Derivative liabilities, non-current	$—	$—	$—
Net unrealized (gain) loss included in Regulatory assets or Regulatory liabilities	$3,561	$7,567	$8,450

Financing Activities

We entered into floating-to-fixed interest rate swap agreements to reduce our exposure to interest rate fluctuations associated with our floating rate debt obligations. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Condensed Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	June 30, 2014	December 31, 2013	June 30, 2013	
	Interest Rate Swaps [(a)]	Interest Rate Swaps [(a)]	Interest Rate Swaps [(b)]	De-designated Interest Rate Swaps [(c)]
Notional	$75,000	$75,000	$150,000	$250,000
Weighted average fixed interest rate	4.97 %	4.97 %	5.04 %	5.67 %
Maximum terms in years	2.5	3.0	3.5	0.5
Derivative liabilities, current	$3,480	$3,474	$6,965	$61,899
Derivative liabilities, non-current	$4,251	$5,614	$12,384	$—

(a) These swaps are designated to borrowings on our Revolving Credit Facility, and are priced using three-month LIBOR, matching the floating portion of the related debt.
At June 30, 2013, $75 million of these interest rate swaps were designated to borrowings on our Revolving Credit Facility and $75 million were designated to borrowings on our project financing debt at Black Hills Wyoming.

(b) These swaps are priced using three-month LIBOR, matching the floating portion of the related debt. The portion of the swaps that were designated to Black Hills Wyoming were settled during the fourth quarter of 2013 upon repayment of the Black Hills Wyoming project financing.

(c) These swaps were settled during the fourth quarter of 2013.

Based on June 30, 2014, market interest rates and balances related to our interest rate swaps, a loss of approximately $3.5 million would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months.

Estimated and actual realized gains or losses will change during future periods as market interest rates change.

Cash Flow Hedges

The impacts of cash flow hedges on our Condensed Consolidated Statements of Income (Loss) were as follows (in thousands):

Three Months Ended June 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$(337)	Interest expense	$(926)		$—
Commodity derivatives	(2,737)	Revenue	(1,251)		—
Total	$(3,074)		$(2,177)		$—

Three Months Ended June 30, 2013

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$1,067	Interest expense	$(1,820)		$—
Commodity derivatives	4,985	Revenue	(28)		—
Total	$6,052		$(1,848)		$—

Six Months Ended June 30, 2014

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$(429)	Interest expense	$(1,820)		$—
Commodity derivatives	(6,209)	Revenue	(1,562)		—
Total	$(6,638)		$(3,382)		$—

Six Months Ended June 30, 2013

Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI Derivative (Effective Portion)	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Reclassified Gain/(Loss) from AOCI into Income (Effective Portion)	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	$1,048	Interest expense	$(3,616	)	$—
Commodity derivatives	2,226	Revenue	1,064		—
Total	$3,274		$(2,552	)	$—

(9) 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, 8 and 10 to the Consolidated Financial Statements included in our 2013 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

Oil and Gas Segment:

- The commodity option contracts for our Oil and Gas segment are valued using the market approach and can include calls and puts. Fair value was derived using quoted prices from third-party brokers for similar instruments as to quantity and timing. The prices are then validated through third-party sources and therefore support Level 2 disclosure.

- The commodity basis swaps for our Oil and Gas segment are valued using the market approach with the instrument's current forward price strip hedged for the same quantity and date and discounted based on the three-month LIBOR. We utilize observable inputs which support a Level 2 disclosure.

Utilities Segments:

- The commodity contracts for our Utilities Segments, valued using the market approach, include exchange-traded futures, options and basis swaps (Level 2) and OTC basis swaps (Level 3) for natural gas contracts. For Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For Level 3 assets and liabilities, fair value was derived using average price quotes from the OTC contract broker and an independent third-party market participant because these instruments are not traded on an exchange.

Corporate Activities:

- The interest rate swaps are valued using the market approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting a Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

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.

The following tables set forth by level within the fair value hierarchy our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments. A discussion of fair value of financial instruments is included in Note 10:

	As of June 30, 2014				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	—	—	—	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	600	—	(600)	—
Commodity derivatives — Utilities	—	4,342	—	(2,605)	1,737
Total	$—	$4,942	$—	$(3,205)	$1,737
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	4,020	—	(4,020)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	2,030	—	(2,030)	—
Commodity derivatives — Utilities	—	5,989	—	(5,989)	—
Interest rate swaps	—	7,731	—	—	7,731
Total	$—	$19,770	$—	$(12,039)	$7,731

	As of December 31, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	130	—	(75)	55
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	815	—	(815)	—
Commodity derivatives —Utilities	—	3,030	—	(2,368)	662
Total	$—	$3,975	$—	$(3,258)	$717
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$—	$—	$—	$—
Basis Swaps -- Oil	—	1,229	—	(1,229)	—
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	531	—	(531)	—
Commodity derivatives — Utilities	—	9,100	—	(9,100)	—
Interest rate swaps	—	9,088	—	—	9,088
Total	$—	$19,948	$—	$(10,860)	$9,088

	As of June 30, 2013				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
	(in thousands)				
Assets:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$45	$—	$(6)	$39
Basis Swaps -- Oil	—	1,109	—	(538)	571
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	1,882	—	(1,589)	293
Commodity derivatives — Utilities	—	1,378	—	(1,378)	—
Total	$—	$4,414	$—	$(3,511)	$903
Liabilities:					
Commodity derivatives — Oil and Gas					
Options -- Oil	$—	$181	$—	$(98)	$83
Basis Swaps -- Oil	—	350	—	(303)	47
Options -- Gas	—	—	—	—	—
Basis Swaps -- Gas	—	445	—	(169)	276
Commodity derivatives — Utilities	—	8,581	—	(8,581)	—
Interest rate swaps	—	87,208	—	(5,960)	81,248
Total	$—	$96,765	$—	$(15,111)	$81,654

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 reflecting 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; however, the amounts do not include net cash collateral on deposit in margin accounts at June 30, 2014, December 31, 2013, and June 30, 2013, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not agree with the amounts presented on our Condensed Consolidated Balance Sheets, nor will they correspond to the fair value measurements presented in Note 8.

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

As of June 30, 2014

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$262	$—
Commodity derivatives	Derivative assets — non-current	338	—
Commodity derivatives	Derivative liabilities — current	—	3,702
Commodity derivatives	Derivative liabilities — non-current	—	2,348
Interest rate swaps	Derivative liabilities — current	—	3,480
Interest rate swaps	Derivative liabilities — non-current	—	4,251
Total derivatives designated as hedges		$600	$13,781
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,737	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	3,384
Total derivatives not designated as hedges		$1,737	$3,384

As of December 31, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$248	$—
Commodity derivatives	Derivative assets — non-current	698	—
Commodity derivatives	Derivative liabilities — current	—	1,541
Commodity derivatives	Derivative liabilities — non-current	—	219
Interest rate swaps	Derivative liabilities — current	—	3,474
Interest rate swaps	Derivative liabilities — non-current	—	5,614
Total derivatives designated as hedges		$946	$10,848
Derivatives not designated as hedges:			

Commodity derivatives	Derivative assets — current	$662	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	—
Commodity derivatives	Derivative liabilities — non-current	—	6,732
Total derivatives not designated as hedges		$662	$6,732

As of June 30, 2013

	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:			
Commodity derivatives	Derivative assets — current	$1,225	$—
Commodity derivatives	Derivative assets — non-current	1,651	—
Commodity derivatives	Derivative liabilities — current	—	889
Commodity derivatives	Derivative liabilities — non-current	—	41
Interest rate swaps	Derivative liabilities — current	—	6,965
Interest rate swaps	Derivative liabilities — non-current	—	12,384
Total derivatives designated as hedges		$2,876	$20,279
Derivatives not designated as hedges:			
Commodity derivatives	Derivative assets — current	$160	$—
Commodity derivatives	Derivative assets — non-current	—	—
Commodity derivatives	Derivative liabilities — current	—	1,884
Commodity derivatives	Derivative liabilities — non-current	—	5,365
Interest rate swaps	Derivative liabilities — current	—	67,859
Interest rate swaps	Derivative liabilities — non-current	—	—
Total derivatives not designated as hedges		$160	$75,108

(10) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 9, were as follows (in thousands) as of:

	June 30, 2014		December 31, 2013		June 30, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$14,697	$14,697	$7,841	$7,841	$30,633	$30,633
Restricted cash and equivalents [(a)]	$2	$2	$2	$2	$7,279	$7,279
Notes payable [(a)]	$132,700	$132,700	$82,500	$82,500	$100,000	$100,000
Long-term debt, including current maturities [(b)]	$1,396,950	$1,578,756	$1,396,948	$1,491,422	$1,214,066	$1,323,543

(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) 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.

(11) OTHER COMPREHENSIVE INCOME (LOSS)

The components of the reclassification adjustments, net of tax, included in Other Comprehensive Income (Loss) for the periods were as follows (in thousands):

	Location on the Condensed Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI			
		Three Months Ended		Six Months Ended	
		June 30, 2014	June 30, 2013	June 30, 2014	June 30, 2013
Gains (losses) on cash flow hedges:					
Interest rate swaps	Interest expense	$926	$1,820	$1,820	$3,616
Commodity contracts	Revenue	1,251	28	1,562	(1,064)
		2,177	1,848	3,382	2,552
Income tax	Income tax benefit (expense)	(774)	(647)	(1,199)	(883)
Reclassification adjustments related to cash flow hedges, net of tax		$1,403	$1,201	$2,183	$1,669
Amortization of defined benefit plans:					
Prior service cost	Utilities - Operations and maintenance	$(25)	$(31)	$(51)	$(62)
	Non-regulated energy operations and maintenance	(84)	(32)	(71)	(64)
Actuarial gain (loss)		158	421	315	842

	Utilities - Operations and maintenance				
	Non-regulated energy operations and maintenance	101	274	186	548
		150	632	379	1,264
Income tax	Income tax benefit (expense)	(52)	(268)	(133)	(443)
Reclassification adjustments related to defined benefit plans, net of tax		$98	$364	$246	$821

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Balances by classification included within Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets are as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges	Employee Benefit Plans	Total
Balance as of December 31, 2012	$(15,713)	$(19,775)	$(35,488)
Other comprehensive income (loss), net of tax	(1,193)	457	(736)
Balance as of March 31, 2013	(16,906)	(19,318)	(36,224)
Other comprehensive income (loss), net of tax	5,079	364	5,443
Balance as of June 30, 2013	$(11,827)	$(18,954)	$(30,781)
Balance as of December 31, 2013	$(7,133)	$(10,289)	$(17,422)
Other comprehensive income (loss), net of tax	(1,478)	311	(1,167)
Balance as of March 31, 2014	(8,611)	(9,978)	(18,589)
Other comprehensive income (loss), net of tax	(556)	(296)	(852)
Balance as of June 30, 2014	$(9,167)	$(10,274)	$(19,441)

(12) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Six months ended	June 30, 2014	June 30, 2013
	(in thousands)	
Non-cash investing and financing activities from continuing operations—		
Property, plant and equipment acquired with accrued liabilities	$40,611	$45,000
Increase (decrease) in capitalized assets associated with asset retirement obligations	$(2,785)	$—
Cash (paid) refunded during the period for continuing operations—		
Interest (net of amounts capitalized)	$(35,009)	$(44,191)
Income taxes, net	$(396)	$(5,406)

(13) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$1,362	$1,608	$2,724	$3,216
Interest cost	3,963	3,825	7,926	7,650
Expected return on plan assets	(4,516)	(4,654)	(9,032)	(9,308)
Prior service cost	16	16	32	32
Net loss (gain)	1,201	3,062	2,403	6,124
Net periodic benefit cost	$2,026	$3,857	$4,053	$7,714

Non-pension Defined Benefit Postretirement Healthcare Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$425	$419	$850	$838
Interest cost	480	417	959	834
Expected return on plan assets	(21)	(20)	(42)	(40)
Prior service cost (benefit)	(107)	(125)	(214)	(250)
Net loss (gain)	40	121	80	242
Net periodic benefit cost	$817	$812	$1,633	$1,624

Supplemental Non-qualified Defined Benefit and Defined Contribution Plans

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Service cost	$374	$348	$749	$696
Interest cost	362	332	724	664
Prior service cost	1	1	1	2
Net loss (gain)	124	198	249	396
Net periodic benefit cost	$861	$879	$1,723	$1,758

Contributions

We anticipate that we will make contributions to the benefit plans during 2014 and 2015. Contributions to the Defined Benefit Pension Plans are cash contributions made directly to the Pension Plan Trust accounts. Contributions to the Healthcare and Supplemental Plan are made in the form of benefit payments. Contributions and anticipated contributions are as follows (in thousands):

	Contributions Made Three Months Ended June 30, 2014	Contributions Made Six Months Ended June 30, 2014	Additional Contributions Anticipated for 2014	Contributions Anticipated for 2015
Defined Benefit Pension Plans	$—	$—	$—	$2,806
Non-pension Defined Benefit Postretirement Healthcare Plans	$956	$1,912	$1,912	$3,822
Supplemental Non-qualified Defined Benefit and Defined Contribution Plans	$373	$746	$746	$1,494

(14) COMMITMENTS AND CONTINGENCIES

There have been no significant changes to commitments and contingencies from those previously disclosed in Note 18 of our Notes to the Consolidated Financial Statements in our 2013 Annual Report on Form 10-K except for those described below.

Bond Purchase Agreements

On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue $160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

Natural Gas Delivery Agreement

In 2012, we entered into a ten-year gas gathering and processing contract for natural gas production from our properties in the Piceance Basin in Colorado, under which we pay a gathering fee per Mcf. The contract requires us to deliver a minimum of 20,000 Mcf per day. This agreement became effective in first quarter of 2014 upon completion of the processing infrastructure capable of handling the committed volumes. We believe that our reserves dedicated to the gathering system, and the projected volumes are adequate to materially satisfy our delivery commitments under this agreement.

Turbine Sale Agreement

On May 6, 2013, Black Hills Wyoming entered into an agreement to sell its 40 MW CTII natural-gas fired generating unit to the City of Gillette, Wyoming for approximately $22 million, upon expiration of the PPA with Cheyenne Light in August 2014. As part of the sale, Black Hills Wyoming will provide services to the City of Gillette through an economy energy PPA. The sale received FERC approval on July 14, 2014, and is expected to close by August 31, 2014.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Cheyenne Light for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Cheyenne Light’s Letter of Credit attached to these bonds.

Other Commitments

Construction of Cheyenne Prairie, a 132 MW natural gas-fired electric generating facility jointly owned by Cheyenne Light and Black Hills Power is expected to cost approximately $222 million. Construction is expected to be completed by September 30, 2014. As of June 30, 2014, committed contracts for equipment purchases and for construction were 100% and 98% complete, respectively.

Oil Creek Fire

On June 29, 2012, a forest and grassland fire occurred in the western Black Hills of Wyoming. A state fire investigator concluded that the fire was caused by the failure of a transmission structure owned, operated and maintained by Black Hills Power. On April 16, 2013, a lawsuit was filed in the United States District Court for the District of Wyoming, which forty-seven plaintiffs and the State of Wyoming have now joined, asserting claims for damages against Black Hills Power. The claims include allegations of negligence, negligence per se, common law nuisance, and trespass. In addition to claims for these compensatory damages, the lawsuit seeks recovery of punitive damages. Our investigation of the cause and origin of the fire is ongoing. We have denied and will vigorously defend all claims arising out of the fire, pending the completion of our investigation. We cannot predict the outcome of our investigation, the viability of alleged claims or the outcome of the litigation.

Civil litigation of this kind, however, is likely to lead to settlement negotiations, including negotiations prompted by pre-trial civil court procedures. We believe such negotiations would effect a settlement of all claims. Regardless of whether the litigation is determined at trial or through settlement, we expect to incur significant investigation, legal and expert services expenses associated with the litigation. We maintain insurance coverage to limit our exposure to losses due to civil liability claims, and related litigation expense. The deductible applicable to some types of claims arising out of this fire is $1.0 million. We expect this coverage to limit our exposure, and we will pursue recoveries to the maximum extent available under the policies. Based upon information currently available, we believe that a loss associated with settlement of pending claims is probable. Accordingly, as of June 30, 2014, we recorded a loss contingency liability related to these claims, and we recorded a receivable for costs we believe are reimbursable and probable of recovery under our insurance coverage. Both of these entries reflect our reasonable estimate of probable future litigation expense and settlement costs; we did not base these contingencies on any determination that it is probable we would be found liable for these claims were they to be litigated.

Given the uncertainty of litigation, however, a loss related to the fire, the litigation and related claims in excess of the loss we have determined to be probable is reasonably possible. However, we cannot reasonably estimate the amount of such possible loss because our investigation and review of damage claims documentation is ongoing, and there are significant factual and legal issues to be resolved. Further claims may be presented by these and other parties. While we have received claims seeking recovery for fire suppression, reclamation and rehabilitation costs, damage to fencing and other personal property, alleged injury to timber, grass or hay, livestock and related operations, and diminished value of real estate, currently totaling $50 million, we are not yet able, for the reasons described above, to reasonably estimate the amount of any reasonable possible losses in excess of the amount we have accrued. Based upon information currently available, however, management does not expect the outcome of the claims to have a material adverse effect upon our consolidated financial condition, results of operations or cash flows.

Dividend Restrictions

Our Revolving Credit Facility and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. As of June 30, 2014, we were in compliance with these 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. The following restrictions on distributions from our subsidiaries existed at June 30, 2014:

- 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. As of June 30, 2014, the restricted net assets at our Utilities Group were approximately $141 million.

(15) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Maximum Exposure at June 30, 2014	Expiration
Indemnification for subsidiary reclamation/surety bonds [(1)]	$65,744	Ongoing

(1) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Condensed Consolidated Balance Sheets.

During the second quarter, guarantees of Black Hills Utility Holdings’ payment obligations up to $70 million arising from commodity transactions for natural gas supply were removed, primarily due to improvement of the corporate credit rating, as well as the conversion of certain guarantees to letters of credit.

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

We are a growth-oriented, vertically-integrated energy company operating principally in the United States with two major business groups — Utilities and Non-regulated Energy. We report our business groups in the following financial segments:

Business Group	Financial Segment
Utilities	Electric Utilities Gas Utilities
Non-regulated Energy	Power Generation Coal Mining Oil and Gas

Our Utilities Group consists of our Electric and Gas Utilities segments. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 203,500 customers in South Dakota, Wyoming, Colorado and Montana; and also distributes natural gas to approximately 35,500 Cheyenne Light customers in Wyoming. Our Gas Utilities serve approximately 538,000 natural gas customers in Colorado, Iowa, Kansas and Nebraska. Our Non-regulated Energy Group consists of our Power Generation, Coal Mining and Oil and Gas segments. Our Power Generation segment produces electric power from our generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts. Our Coal 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 Oil and Gas segment engages in exploration, development and production of crude oil and natural gas, primarily in the Rocky Mountain region.

Certain industries in which we operate are highly seasonal, and revenue from, and certain expenses for, such operations may fluctuate significantly among quarterly periods. Demand for electricity and natural gas is sensitive to seasonal cooling, heating and industrial load requirements, as well as changes in market prices. In particular, the normal peak usage season for electric utilities is June through August while the normal peak usage season for gas utilities is November through March. Significant earnings variances can be expected between the Gas Utilities segment’s peak and off-peak seasons. Due to this seasonal nature, our results of operations for the three and six months ended June 30, 2014 and 2013, and our financial condition as of June 30, 2014, December 31, 2013 and June 30, 2013, 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 59.

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

Results of Operations

Executive Summary, Significant Events and Overview

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. Net income (loss) for the three months ended June 30, 2014 was $20 million, or $0.44 per share, compared to Net income (loss) of $31 million, or $0.69 per share, reported for the same period in 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. Net income (loss) for the six months ended June 30, 2014 was $68 million, or $1.52 per share, compared to Net income (loss) of $74 million, or $1.66 per share, reported for the same period in 2013.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
Revenue						
Utilities	$264,383	$263,868	$515	$705,822	$626,310	$79,512
Non-regulated Energy	51,779	46,257	5,522	104,475	95,544	8,931
Inter-company eliminations	(32,925)	(30,299)	(2,626)	(66,891)	(61,357)	(5,534)
	$283,237	$279,826	$3,411	$743,406	$660,497	$82,909
Net income (loss)						
Electric Utilities	$11,427	$10,610	$817	$26,002	$22,966	$3,036
Gas Utilities	1,994	3,192	(1,198)	26,692	21,675	5,017
Utilities	13,421	13,802	(381)	52,694	44,641	8,053
Power Generation	7,194	5,031	2,163	15,267	10,675	4,592
Coal Mining	2,016	1,973	43	4,480	3,038	1,442
Oil and Gas	(1,660)	(1,964)	304	(3,682)	(2,017)	(1,665)
Non-regulated Energy	7,550	5,040	2,510	16,065	11,696	4,369
Corporate activities and eliminations (a)	(1,151)	11,676	(12,827)	(821)	17,378	(18,199)
Net income (loss)	$19,820	$30,518	$(10,698)	$67,938	$73,715	$(5,777)

(a) Corporate activities for the three and six months ended June 30, 2013 include a $12 million and a $17 million net after-tax non-cash mark-to-market gain on certain interest rate swaps. These same interest rate swaps were settled in November 2013.

Overview of Business Segments and Corporate Activity

Utilities Group

- Gas Utilities experienced milder weather during the three months ended June 30, 2014 resulting in a 16% decrease in heating degree days compared to the same period in 2013. Year-to-date results were favorably impacted by colder weather during the first quarter of 2014. Heating degree days were 2% higher for the six months ended June 30, 2014, compared to the same period in 2013. Heating degree days for the three and six months ended June 30, 2014 were 5% and 12% higher than normal, respectively, compared to 24% and 9% higher than normal for the same periods in 2013.

- Construction continued on Cheyenne Prairie, a natural gas-fired electric generating facility to serve Cheyenne Light and Black Hills Power customers. The 132 MW generation project is expected to cost approximately $222 million, exclusive of construction financing costs which are being recovered through construction financing riders. The Electric Utilities recorded additional gross margins of approximately $3.7 million and $7.8 million, respectively, for the three and six months ended June 30, 2014, related to these riders. To date, we have expended approximately $196 million. The project is expected to be completed at or less than budget and is on schedule to be placed into service in October 2014.

- On July 31, 2014, the WPSC approved rate case settlement agreements authorizing an increase for Cheyenne Light of $8.4 million and $0.8 million for annual electric and natural gas revenue, respectively, effective October 1, 2014. The settlement also included a return on equity of 9.9%, and a capital structure of 54% equity and 46% debt.

- On July 22, 2014, Black Hills Power filed a CPCN with the WPSC to construct the Wyoming portion of a $54 million, 230-kV, 144 mile-long transmission line that would connect the Teckla Substation in northeast Wyoming, to the Lange Substation near Rapid City, South Dakota. On June 30, 2014, Black Hills Power filed an application with the SDPUC, for a permit to construct the South Dakota portion of this line. Approval by the WPSC and SDPUC is anticipated in the fourth quarter of 2014.

- On June 30, 2014, Black Hills Power and Cheyenne Light entered into agreements to issue $160 million of first mortgage bonds to finance Cheyenne Prairie. Black Hills Power will issue $85 million of 4.43% coupon first mortgage bonds due October 20, 2044, and Cheyenne Light will issue $75 million of 4.53% coupon first mortgage bonds due October 20, 2044. The closing for the sale of the first mortgage bonds for both utilities is anticipated to be October 1, 2014, subject to satisfaction of customary closing conditions.

- On May 5, 2014, Colorado Electric issued an all-source generation request for approximately 42 MW of summer seasonal firm capacity in 2017, 2018, and 2019, and up to 60 MW of eligible renewable energy resources to serve its customers in southern Colorado. Colorado IPP submitted solar and wind bids in response to this request. Proposed bids were due by July 31, 2014, and pending Colorado Electric’s review of the bids and other regulatory proceedings, a CPUC decision on Colorado Electric’s portfolio of generation resources is expected by the end of February 2015.

- On April 30, 2014, Colorado Electric filed a rate request with the CPUC for an annual revenue increase of $8.0 million to recover operating expenses and infrastructure investments, including those for the Busch Ranch Wind Farm. Colorado Electric seeks approval of a new rider pursuant to the Clean Air-Clean Jobs Act Adjustment, to recover a return on the expenditures associated with the construction of a $65 million natural gas-fired combustion turbine unit, previously approved by the CPUC to replace the W.N. Clark retirement. The filing seeks a return on equity of 10.3% and a capital structure of approximately 50.5% equity and 49.5% debt. A subsequent filing on June 27, 2014 reduced our request to $7.2 million to reflect updated cost information.

- On April 29, 2014, Kansas Gas filed a rate request with the KCC to increase annual revenue by $7.3 million primarily to recover infrastructure and increased operating costs. The filing seeks a return on equity of 10.6%, and a capital structure of approximately 50.3% equity and 49.7% debt.

- On April 25, 2014 Cheyenne Light received FERC approval to establish rates for transmission services under their Open Access Transmission Tariff, effective May 3, 2014. The approval includes a return on equity of 10.6% and a capital structure of 54% equity and 46% debt.

- On March 31, 2014, Black Hills Power filed a rate request with the SDPUC to increase annual revenue by $14.6 million to recover operating expenses and infrastructure investments, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25%, and a capital structure of approximately 53.3% equity and 46.7% debt.

- On March 21, 2014, Black Hills Power retired the Ben French, Neil Simpson I, and Osage coal-fired power plants. These three plants totaling 81 MW were closed because of federal environmental regulations. These plants will largely be replaced by Black Hills Power's share of Cheyenne Prairie.

- On February 25, 2014, the CPUC issued a final order after rehearing, approving a CPCN for the retirement of Pueblo Unit #5 and #6, effective December 31, 2013.

- On January 17, 2014, Black Hills Power filed a rate request with the WPSC for an annual revenue increase of $2.8 million to recover investments made in electric infrastructure, primarily for Cheyenne Prairie. The filing seeks a return on equity of 10.25% and a capital structure of approximately 53.3% equity and 46.7% debt.

- Our Utilities Group continued its efforts to acquire small municipal gas distribution systems adjacent to our existing service territories. During the first quarter of 2014, we acquired an additional gas system, adding approximately 70 customers, and we announced the pending acquisition of assets serving approximately 400 customers.

Non-regulated Energy Group

- Oil and Gas production volumes increased 15% and 5%, respectively, for the three and six months ended June 30, 2014. The average hedged price received increased for natural gas by 35% and 24% and decreased for oil by 18% and 8%, respectively for the three and six months ended June 30, 2014 compared to the same periods in 2013.

- On July 14, 2014, Black Hills Wyoming received FERC approval for the sale of its 40 MW CTII natural gas-fired unit to the City of Gillette, Wyoming for approximately $22 million. The sale is expected to close on August 31, 2014 upon expiration of the PPA with Cheyenne Light.

- Drilling commenced in June 2014 in the southern Piceance Basin on two of the six horizontal Mancos Shale wells planned for 2014.

- Production continued from the two horizontal Mancos Shale wells placed on production during the first quarter of 2014. On March 6, 2014, the Summit Midstream cryogenic gas processing plant with a capacity of 20,000 Mcf per day started serving the company's gas production in the southern Piceance Basin, including the two Mancos Shale wells placed on production during the first quarter.

Corporate Activities

- On June 13, 2014, Fitch upgraded the BHC credit rating to BBB+ with a stable outlook.

- On May 29, 2014, we amended our $500 million corporate Revolving Credit Facility agreement to extend the term through May 29, 2019. This facility is substantially similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase the capacity of the facility to $750 million. Borrowings continue to be available under a base rate or various Eurodollar rate options for which the borrowing rates were reduced under the amended agreement.

- On January 30, 2014, Moody's upgraded our corporate credit rating to Baa1 from Baa2 with continued stable outlook.

- Consolidated interest expense decreased by approximately $5.5 million and $11 million for the three and six months ended June 30, 2014, respectively, compared to the three and six months ended June 30, 2013, due primarily to the refinancing activities occurring during the fourth quarter of 2013.

Operating Results

A discussion of operating results from our segments and Corporate activities follows.

Utilities Group

We report two segments within the Utilities Group: Electric Utilities and Gas Utilities. The Electric Utilities segment includes the electric operations of Black Hills Power, Colorado Electric and the electric and natural gas operations of Cheyenne Light. The Gas Utilities segment includes the regulated natural gas utility operations of Black Hills Energy in Colorado, Iowa, Kansas and Nebraska.

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

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

Electric Utilities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Variance	2014	2013	Variance
	(in thousands)					
Revenue — electric	$154,544	$151,775	$2,769	$322,909	$302,148	$20,761
Revenue — gas	7,340	6,257	1,083	21,077	18,514	2,563
Total revenue	161,884	158,032	3,852	343,986	320,662	23,324
Fuel, purchased power and cost of gas — electric	69,723	67,349	2,374	148,142	133,038	15,104
Purchased gas — gas	4,051	2,515	1,536	12,325	8,953	3,372
Total fuel, purchased power and cost of gas	73,774	69,864	3,910	160,467	141,991	18,476
Gross margin — electric	84,821	84,426	395	174,767	169,110	5,657
Gross margin — gas	3,289	3,742	(453)	8,752	9,561	(809)
Total gross margin	88,110	88,168	(58)	183,519	178,671	4,848
Operations and maintenance	40,272	39,383	889	82,872	78,218	4,654
Depreciation and amortization	19,274	19,665	(391)	38,361	38,826	(465)
Total operating expenses	59,546	59,048	498	121,233	117,044	4,189

Operating income	28,564	29,120	(556)	62,286	61,627	659
Interest expense, net	(11,829)	(13,810)	1,981	(23,841)	(28,207)	4,366
Other income (expense), net	352	173	179	608	458	150
Income tax benefit (expense)	(5,660)	(4,873)	(787)	(13,051)	(10,912)	(2,139)
Net income (loss)	$11,427	$10,610	$817	$26,002	$22,966	$3,036

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	Three Months Ended June 30,		Six Months Ended June 30,	
Revenue - Electric (in thousands)	2014	2013	2014	2013
Residential:				
Black Hills Power	$14,332	$13,535	$34,392	$29,977
Cheyenne Light	8,167	8,307	17,840	17,637
Colorado Electric	21,316	21,829	45,995	45,950
Total Residential	43,815	43,671	98,227	93,564
Commercial:				
Black Hills Power	21,200	18,913	42,728	36,397
Cheyenne Light	15,238	14,476	29,631	27,243
Colorado Electric	23,101	21,663	44,991	42,814
Total Commercial	59,539	55,052	117,350	106,454
Industrial:				
Black Hills Power	7,534	7,210	14,869	13,220
Cheyenne Light	7,304	5,344	14,528	10,199
Colorado Electric	9,535	9,647	18,573	19,284
Total Industrial	24,373	22,201	47,970	42,703
Municipal:				
Black Hills Power	846	847	1,638	1,561
Cheyenne Light	514	490	968	948
Colorado Electric	3,277	3,492	6,584	6,039
Total Municipal	4,637	4,829	9,190	8,548
Total Retail Revenue - Electric	132,364	125,753	272,737	251,269
Contract Wholesale:				
Total Contract Wholesale - Black Hills Power	4,473	4,926	10,071	10,693
Off-system Wholesale:				