CABOT OIL & GAS CORP
Form 10-Q
July 26, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

For the quarterly period ended June 30, 2013

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE	**04-3072771**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza

840 Gessner Road, Suite 1400, Houston, Texas 77024

(Address of principal executive offices including ZIP code)

(281) 589-4600

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months 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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit 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. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

As of July 22, 2013, there were 210,764,304 shares of Common Stock, Par Value $.10 Per Share, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	June 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 47,277	$ 30,736
Accounts receivable, net	204,970	172,419
Income taxes receivable	7,273	
Inventories	18,276	14,173
Deferred income taxes	50,864	
Derivative instruments	69,644	50,824
Other current assets	4,889	2,158
Total current assets	403,193	270,310
Properties and equipment, net (Successful efforts method)	4,558,207	4,310,977
Derivative instruments	17,963	
Other assets	38,573	35,026
	$ 5,017,936	$ 4,616,313
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 356,851	$ 312,480
Current portion of long-term debt	75,000	75,000
Accrued liabilities	58,571	49,789
Income taxes payable	3,969	1,667
Deferred income taxes		5,203
Total current liabilities	494,391	444,139
Postretirement benefits	40,313	38,864
Long-term debt	1,067,000	1,012,000
Deferred income taxes	1,015,493	882,672
Asset retirement obligation	68,390	67,016
Other liabilities	46,108	40,175
Total liabilities	2,731,695	2,484,866
Commitments and contingencies		
Stockholders equity		
Common stock:		
Authorized 480,000,000 shares of $0.10 par value in 2013 and 2012, respectively		
Issued 210,758,335 shares and 210,429,731 shares in 2013 and 2012, respectively	21,076	21,043

Additional paid-in capital		725,156		716,609
Retained earnings		1,496,795		1,373,264
Accumulated other comprehensive income / (loss)		46,563		23,880
Less treasury stock, at cost:				
404,400 shares in 2013 and 2012, respectively		(3,349)		(3,349)
Total stockholders equity		2,286,241		2,131,447
	$	5,017,936	$	4,616,313

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
OPERATING REVENUES				
Natural gas	$ 368,391	$ 201,051	$ 662,184	$ 407,833
Crude oil and condensate	70,226	57,466	135,881	107,447
Brokered natural gas	8,244	5,149	19,137	18,593
Other	2,819	1,991	5,763	3,920
	449,680	265,657	822,965	537,793
OPERATING EXPENSES				
Direct operations	36,978	29,306	68,475	56,626
Transportation and gathering	52,648	33,139	98,869	63,397
Brokered natural gas cost	6,704	4,250	15,093	16,122
Taxes other than income	11,364	10,854	23,051	29,437
Exploration	4,529	16,244	8,553	20,245
Depreciation, depletion and amortization	151,389	114,616	300,042	224,973
General and administrative	21,608	46,872	57,312	69,421
	285,220	255,281	571,395	480,221
Gain / (loss) on sale of assets	276	67,703	180	67,168
INCOME FROM OPERATIONS	164,736	78,079	251,750	124,740
Interest expense and other	16,701	18,495	32,956	35,412
Income before income taxes	148,035	59,584	218,794	89,328
Income tax expense	58,921	23,647	86,856	35,073
NET INCOME	$ 89,114	$ 35,937	$ 131,938	$ 54,255
Earnings per share				
Basic	$ 0.42	$ 0.17	$ 0.63	$ 0.26
Diluted	$ 0.42	$ 0.17	$ 0.62	$ 0.26
Weighted-average shares outstanding				
Basic	210,349	209,512	210,250	209,320
Diluted	211,745	211,158	211,492	210,974
Dividends per common share	$ 0.02	$ 0.02	$ 0.04	$ 0.04

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (Unaudited)

(In thousands)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income	$ 89,114	$ 35,937	$ 131,938	$ 54,255
Other comprehensive income / (loss), net of taxes:				
Reclassification adjustment for settled hedge contracts *(1)*	(1,105)	(44,579)	(10,430)	(78,649)
Changes in fair value of hedge contracts *(2)*	69,839	11,246	32,864	54,451
Pension and postretirement benefits:				
Amortization of prior service cost *(3)*		67		135
Amortization of net loss *(4)*	124	4,174	249	8,349
Total other comprehensive income / (loss)	68,858	(29,092)	22,683	(15,714)
Comprehensive income / (loss)	$ 157,972	$ 6,845	$ 154,621	$ 38,541

(1) Net of income taxes of $717 and $28,263 for the three months ended June 30, 2013 and 2012, respectively, and $6,762 and $49,863 for the six months ended June 30, 2013 and 2012, respectively.

(2) Net of income taxes of $(45,274) and $(7,130) for the three months ended June 30, 2013 and 2012, respectively, and $(21,303) and $(34,653) for the six months ended June 30, 2013 and 2012, respectively.

(3) Net of income taxes of $0 and $(43) for the three months ended June 30, 2013 and 2012, respectively, and $0 and $(86) for the six months ended June 30, 2013 and 2012, respectively.

(4) Net of income taxes of $(81) and $(2,647) for the three months ended June 30, 2013 and 2012, respectively, and $(161) and $(5,294) for the six months ended June 30, 2013 and 2012, respectively.

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

(In thousands)	**Six Months Ended June 30, 2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 131,938	$ 54,255
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	300,042	224,973
Deferred income tax expense	69,662	27,073
(Gain) / loss on sale of assets	(180)	(67,168)
Exploration expense	806	10,925
Unrealized (gain) / loss on derivative instruments		300
Amortization of debt issuance costs	1,842	3,334
Stock-based compensation, pension and other	27,355	26,987
Changes in assets and liabilities:		
Accounts receivable, net	(32,551)	25,214
Inventories	(4,103)	9,293
Other current assets	(2,733)	(3,691)
Accounts payable and accrued liabilities	9,661	(28,675)
Income taxes	(4,971)	4,775
Other assets and liabilities	547	3,547
Stock-based compensation tax benefit	(7,348)	
Net cash provided by operating activities	489,967	291,142
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(524,056)	(411,327)
Proceeds from sale of assets	906	132,715
Investment in equity method investment	(4,250)	(2,088)
Net cash used in investing activities	(527,400)	(280,700)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from debt	325,000	170,000
Repayments of debt	(270,000)	(148,000)
Stock-based compensation tax benefit	7,348	
Dividends paid	(8,407)	(8,368)
Capitalized debt issuance costs		(5,005)
Other	33	(339)
Net cash provided by financing activities	53,974	8,288
Net (decrease) / increase in cash and cash equivalents	16,541	18,730
Cash and cash equivalents, beginning of period	30,736	29,911
Cash and cash equivalents, end of period	$ 47,277	$ 48,641

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies disclosed in its Annual Report on Form 10-K for the year ended December 31, 2012 (Form 10-K) filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the consolidated financial statements and information presented in the Form 10-K. In management s opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair statement. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Certain reclassifications have been made to prior year statements to conform with current year presentation. These reclassifications have no impact on previously reported net income.

With respect to the unaudited financial information of the Company as of June 30, 2013 and for the three and six months ended June 30, 2013 and 2012, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated July 26, 2013 appearing herein states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Recent Accounting Pronouncements

Effective January 1, 2013, the Company adopted the amended disclosure requirements prescribed in Accounting Standards Update (ASU) No. 2011-11, Disclosures about Offsetting Assets and Liabilities and ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. This guidance impacted the disclosures associated with the Company s commodity derivatives (Note 7) and did not impact its consolidated financial position, results of operations or cash flows.

Effective January 1, 2013, the Company adopted the amended disclosure requirements prescribed in ASU No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This guidance impacted the Company s disclosures associated with items reclassified from accumulated other comprehensive income / (loss) (Note 9) and did not impact its consolidated financial position, results of operations or cash flows.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)		June 30, 2013		December 31, 2012
Proved oil and gas properties	$	6,245,196	$	5,724,940
Unproved oil and gas properties		458,047		467,483
Gathering and pipeline systems		240,062		239,656
Land, building and other equipment		90,690		86,137
		7,033,995		6,518,216
Accumulated depreciation, depletion and amortization		(2,475,788)		(2,207,239)
	$	4,558,207	$	4,310,977

At June 30, 2013, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling.

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Divestitures

In June 2012, the Company sold a 35% non-operated working interest associated with certain of its Pearsall Shale undeveloped leaseholds in south Texas to a wholly-owned subsidiary of Osaka Gas Co., Ltd. (Osaka) for total consideration of approximately $251.0 million. The Company received $125.0 million in cash proceeds and Osaka agreed to fund 85% of the Company s share of future drilling and completion costs associated with these leaseholds until it has paid approximately $126.0 million in accordance with a joint development agreement entered into at the closing. The Company recognized a $67.0 million gain on sale of assets associated with this sale. The drilling and completion carry under the joint development agreement will terminate two years after the closing of the transaction; however, based on the Company s current drilling and completion activities in the Pearsall Shale, the Company expects that the carry will be fully satisfied in the second half of 2013.

3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)		**June 30, 2013**		**December 31, 2012**
Accounts receivable, net				
Trade accounts	$	193,695	$	165,070
Joint interest accounts		6,694		5,659
Other accounts		6,260		2,817
		206,649		173,546
Allowance for doubtful accounts		(1,679)		(1,127)
	$	204,970	$	172,419
Inventories				
Natural gas in storage	$	8,629	$	7,494
Tubular goods and well equipment		9,274		6,392
Other accounts		373		287
	$	18,276	$	14,173
Other current assets				
Prepaid balances and other		4,889		2,158
	$	4,889	$	2,158
Other assets				
Deferred compensation plan	$	11,416	$	10,608
Debt issuance cost		15,578		17,420
Equity method investment		11,501		6,915
Other accounts		78		83
	$	38,573	$	35,026
Accounts payable				
Trade accounts	$	19,134	$	14,037
Natural gas purchases		6,335		4,892
Royalty and other owners		81,743		66,321
Accrued capital costs		184,891		164,862

Taxes other than income		6,947		10,224
Drilling advances		51,026		44,203
Producer gas imbalances		1,368		1,602
Other accounts		5,407		6,339
	$	356,851	$	312,480
Accrued liabilities				
Employee benefits	$	20,779	$	16,011
Postretirement benefits		1,304		1,304
Taxes other than income		11,374		8,735
Interest payable		22,128		22,329
Derivative instruments				192
Other accounts		2,986		1,218
	$	58,571	$	49,789
Other liabilities				
Deferred compensation plan	$	30,385	$	23,893
Other accounts		15,723		16,282
	$	46,108	$	40,175

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4. DEBT AND CREDIT AGREEMENTS

The Company s debt and credit agreements consisted of the following:

(In thousands)	June 30, 2013	December 31, 2012
Total debt		
7.33% weighted-average fixed rate notes	$ 95,000	$ 95,000
6.51% weighted-average fixed rate notes	425,000	425,000
9.78% notes	67,000	67,000
5.58% weighted-average fixed rate notes	175,000	175,000
Credit facility	380,000	325,000
Current maturities		
7.33% weighted-average fixed rate notes	(75,000)	(75,000)
Long-term debt, excluding current maturities	$ 1,067,000	$ 1,012,000

Effective April 17, 2013, the lenders under the Company s revolving credit facility approved an increase in the Company s borrowing base from $1.7 billion to $2.3 billion as part of the annual redetermination under the terms of the credit facility. The Company s commitments under the credit facility of $900.0 million remained unchanged. At June 30, 2013, the Company had $380.0 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 2.0% and $519.0 million available for future borrowings.

5. EARNINGS PER COMMON SHARE

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2013	2012	2013	2012
Weighted-average shares - basic	210,349	209,512	210,250	209,320
Dilution effect of stock appreciation rights and stock awards at end of period	1,396	1,646	1,242	1,654
Weighted-average shares - diluted	211,745	211,158	211,492	210,974
Weighted-average stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect	1	122	287	179

6. COMMITMENTS AND CONTINGENCIES

Contractual Obligations

The Company has various contractual obligations in the normal course of its operations. Except for certain amended transportation agreements and two new drilling rig commitments described below, there have been no material changes to our contractual obligations described under Transportation Agreements , Drilling Rig Commitments and Lease Commitments as disclosed in Note 8 in the Notes to Consolidated Financial Statements included in the Form 10-K.

Transportation Agreements

During the second quarter of 2013, the Company amended certain natural gas transportation agreements associated with the Company s production in Pennsylvania. This amendment increased the Company s future aggregate obligations under its transportation agreements by approximately $25.3 million compared to those amounts in disclosed in Note 8 in the Notes to Consolidated Financial Statements included in the Form 10-K.

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Drilling Rig Commitments

During the second quarter of 2013, the Company entered into two drilling rig commitments for its capital program in the Marcellus Shale that are expected to commence in the third and fourth quarters of 2013 and have initial terms of two and three years, respectively. There have been no material changes to the Company s existing drilling rig commitments previously disclosed in Note 8 in the Notes to the Consolidated Financial Statements included in the Form 10-K. The future minimum commitments under all of the Company s drilling rig commitments as of June 30, 2013 are approximately $7.0 million in 2013, $14.9 million in 2014, $6.8 million in 2015 and $4.4 million in 2016.

Legal Matters

The Company is a defendant in various legal proceedings arising in the normal course of business. All known liabilities are accrued when management determines they are probable based on its best estimate of the potential loss. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company s financial position, results of operations or cash flows.

Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional losses with respect to those matters in which reserves have been established. The Company believes that any such amount above the amounts accrued is not material to the Condensed Consolidated Financial Statements. Future changes in facts and circumstances not currently foreseeable could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Environmental Matters

Pennsylvania Department of Environmental Protection

On December 15, 2010, the Company entered into a consent order and settlement agreement (CO&SA) with the Pennsylvania Department of Environmental Protection (PaDEP), addressing a number of environmental issues originally identified in 2008 and 2009, including alleged releases of drilling mud and other substances, alleged record keeping violations at various wells and alleged natural gas contamination of water supplies to 14 households in Susquehanna County, Pennsylvania. During 2010 and 2011, the Company paid a total of $1.3 million in settlement of fines and penalties sought or claimed by the PaDEP related to this matter. On January 11, 2011, certain of the affected households appealed the CO&SA to the Pennsylvania Environmental Hearing Board (PEHB). On October 17, 2011, the Company requested PaDEP approval to resume hydraulic fracturing and new natural gas well drilling operations in the affected area, along with a request to cease temporary water deliveries to the affected households pursuant to prior consent orders with the PaDEP. The PaDEP concurred that temporary water deliveries to the property owners are no longer necessary. On November 18, 2011, certain of the affected households appealed this order to the PEHB, which appeal was later consolidated with the CO&SA appeal. All appellants have accepted their portion of the $2.2 million that was placed into escrow in 2011 for their benefit and on October 18, 2012 had dismissed their appeal to the PEHB. Subsequent to the withdrawal of the appeals, the PEHB allowed three groups of appellants to reinstate their appeal. It is expected that the PEHB will hold a hearing with respect to the appellants appeal in the second half of 2013.

The Company is in continuing discussions with the PaDEP to address the results of the Company s natural gas well test data, water quality sampling and water well headspace screenings, which were required pursuant to the CO&SA. On August 21, 2012, the PaDEP notified the Company that it could commence completion operations on existing wells within the concerned area.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Company periodically enters into commodity derivative instruments to hedge its exposure to price fluctuations related to its natural gas and crude oil production. The Company s credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company s risk management policies and where such derivatives do not subject the Company to material speculative risks. All of the Company s derivatives are used for risk management purposes and are not held for trading purposes.

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As of June 30, 2013, the Company had the following outstanding commodity derivatives:

				Collars				Swaps
				Floor		Ceiling		
Type of Contract	Volume		Contract Period	Range *(1)*	Weighted Average *(1)*	Range *(1)*	Weighted Average *(1)*	(Weighted Average) *(1)*
Natural gas collars	8.9	Bcf	Jul. 2013 - Dec. 2013	$	$ 5.15	$ 6.18-$6.23	$ 6.20	
Natural gas collars	109.0	Bcf	Jul. 2013 - Dec. 2013	$ 3.09-$4.37	$ 3.63	$ 3.98-$5.02	$ 4.27	
Natural gas collars	53.3	Bcf	Jul. 2013 - Dec. 2014	$ 3.60-$3.96	$ 3.78	$ 4.55-$4.59	$ 4.57	
Natural gas collars	124.1	Bcf	Jan. 2014 - Dec. 2014	$ 3.86-$4.37	$ 4.19	$ 4.63-$4.80	$ 4.70	
Crude oil swaps	552	Mbbl	Jul. 2013 - Dec. 2013					$ 101.90

(1) Natural gas prices are stated per Mcf and crude oil prices are stated per barrel.

The changes in the fair value of derivatives designated as hedges that are effective are recorded to accumulated other comprehensive income / (loss) in stockholders equity in the Condensed Consolidated Balance Sheet. The ineffective portion of the change in fair value of derivatives designated as hedges, if any, and the change in fair value of derivatives not designated as hedges are recorded currently in earnings as a component of natural gas revenue and crude oil and condensate revenue in the Condensed Consolidated Statement of Operations.

The following disclosures reflect the impact of derivative instruments on the Company s condensed consolidated financial statements:

Effect of Derivative Instruments on the Condensed Consolidated Balance Sheet

		Fair Values of Derivative Instruments			
		Derivative Assets		Derivative Liabilities	
(In thousands)	**Balance Sheet Location**	**June 30, 2013**	**December 31, 2012**	**June 30, 2013**	**December 31, 2012**
Derivatives Designated as Hedging Instruments					
Commodity contracts	Derivative instruments (current assets)	$ 69,644	$ 50,824	$	$
Commodity contracts	Derivative instruments (non-current assets)	17,963			
Commodity contracts	Accrued liabilities				192
Commodity contracts	Derivative instruments (non-current liabilities)				

	$ 87,607	$ 50,824	$	$ 192

At June 30, 2013 and December 31, 2012, unrealized gains of $87.6 million ($53.1 million, net of tax) and unrealized gains of $50.6 million ($30.7 million, net of tax), respectively, were recorded in accumulated other comprehensive income / (loss) in stockholder s equity in the Condensed Consolidated Balance Sheet. Based upon estimates at June 30, 2013, the Company expects to reclassify $42.3 million in after-tax income associated with its commodity hedges from accumulated other comprehensive income / (loss) to the Condensed Consolidated Statement of Operations over the next 12 months.

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Offsetting of Derivative Assets and Liabilities in the Condensed Consolidated Balance Sheet

(In thousands)		June 30, 2013		December 31, 2012
Derivative Assets				
Gross amounts of recognized assets	$	89,840	$	54,454
Gross amounts offset in the statement of financial position		(2,233)		(3,630)
Net amounts of assets presented in the statement of financial position		87,607		50,824
Gross amounts of financial instruments not offset in the statement of financial position		549		1,892
Net amount	$	88,156	$	52,716
Derivative Liabilities				
Gross amounts of recognized liabilities	$	2,233	$	3,822
Gross amounts offset in the statement of financial position		(2,233)		(3,630)
Net amounts of liabilities presented in the statement of financial position				192
Gross amounts of financial instruments not offset in the statement of financial position				
Net amount	$		$	192

Effect of Derivative Instruments on the Condensed Consolidated Statement of Operations

Derivatives Designated as Hedging Instruments

	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)							
	Three Months Ended June 30,				Six Months Ended June 30,			
(In thousands)		2013		2012		2013		2012
Commodity Contracts	$	115,113	$	18,376	$	54,167	$	89,104

Location of Gain (Loss) Reclassified from Accumulated OCI into Income (In thousands)	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)							
	Three Months Ended June 30,				Six Months Ended June 30,			
		2013		2012		2013		2012
Natural gas revenues	$	(272)	$	69,732	$	13,056	$	126,728
Crude oil and condensate revenues		2,094		3,110		4,136		1,784
	$	1,822	$	72,842	$	17,192	$	128,512

For the three and six months ended June 30, 2013 and 2012, respectively, there was no ineffectiveness recorded in our Condensed Consolidated Statement of Operations related to our derivative instruments.

Derivatives Not Designated as Hedging Instruments

(In thousands)	Location of Gain (Loss) Recognized in Income on Derivatives	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Commodity Contracts	Natural gas revenues	$	$ (342)	$	$ (300)

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligation under the agreement. The Company enters into derivative contracts with multiple counterparties in order to limit its exposure to individual counterparties. The Company also has netting arrangements with each of its counterparties that allow it to offset assets and liabilities from separate derivative contracts with that counterparty.

Certain counterparties to the Company s derivative instruments are also lenders under its credit facility. The Company s credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liabilities in certain situations.

8. FAIR VALUE MEASUREMENTS

The Company follows the authoritative guidance for measuring fair value of assets and liabilities in its financial statements. The authoritative guidance also established a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements. The Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. For further information regarding the fair value hierarchy, refer to Note 14 of the Notes to the Consolidated Financial Statements in the Form 10-K.

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Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of long-lived assets, at fair value on a nonrecurring basis. As none of the Company s non-financial assets and liabilities were impaired as of June 30, 2013 and 2012 and no other assets or liabilities were required to be measured at fair value on a non-recurring basis, additional disclosures are not provided.

The estimated fair value of the Company s asset retirement obligation at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligation is deemed to use Level 3 inputs.

Financial Assets and Liabilities

The following fair value hierarchy table presents information about the Company s financial assets and liabilities measured at fair value on a recurring basis:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	June 30, 2013
Assets				
Deferred compensation plan	$ 11,416	$	$	$ 11,416
Derivative instruments		3,729	83,878	87,607
Total assets	$ 11,416	$ 3,729	$ 83,878	$ 99,023
Liabilities				
Deferred compensation plan	$ 30,385	$	$	$ 30,385
Derivative instruments				
Total liabilities	$ 30,385	$	$	$ 30,385

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	December 31, 2012
Assets				
Deferred compensation plan	$ 10,608	$	$	$ 10,608
Derivative instruments		9,473	41,351	50,824
Total assets	$ 10,608	$ 9,473	$ 41,351	$ 61,432
Liabilities				

Deferred compensation plan	$	23,893	$		$		$	23,893
Derivative instruments						192		192
Total liabilities	$	23,893	$		$	192	$	24,085

The Company s investments associated with its deferred compensation plan consist of mutual funds and deferred shares of the Company s common stock that are publicly traded and for which market prices are readily available.

The derivative instruments were measured based on quotes from the Company s counterparties. Such quotes have been derived using an income approach that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, basis differentials, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. Estimates are verified using relevant NYMEX futures contracts and compares them to multiple quotes obtained from counterparties for reasonableness. The determination of the fair values presented above also incorporates a credit adjustment for nonperformance risk. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions

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in which it has derivative transactions, while nonperformance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	**2013**	**2012**	**2013**	**2012**
Balance at beginning of period	$ (29,899)	$ 218,942	$ 41,159	$ 195,127
Total gains / (losses) (realized or unrealized):				
Included in earnings *(1)*	(272)	69,390	13,056	126,428
Included in other comprehensive income	113,777	(90,234)	42,719	(67,541)
Settlements	272	(68,885)	(13,056)	(125,186)
Transfers in and/or out of level 3				385
Balance at end of period	$ 83,878	$ 129,213	$ 83,878	$ 129,213

(1) There were no unrealized gains or losses for the three and six months ended June 30, 2013. Unrealized losses of $0.3 million for the three and six months ended June 30, 2012, respectively, were included in natural gas revenues in the Condensed Consolidated Statement of Operations.

There were no transfers between Level 1 and Level 2 measurements for the three and six months ended June 30, 2013 and 2012.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company s default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company s fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all fixed-rate notes and the credit facility is based on interest rates currently available to the Company. The Company s long-term debt is valued using an income approach and classified as Level 3 in the fair value hierarchy due to the unobservable nature of the inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	June 30, 2013		December 31, 2012	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Total debt	$ 1,142,000	$ 1,235,176	$ 1,087,000	$ 1,213,474
Current maturities	(75,000)	(75,301)	(75,000)	(77,175)
Long-term debt, excluding current maturities	$ 1,067,000	$ 1,159,875	$ 1,012,000	$ 1,136,299

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9. ACCUMULATED OTHER COMPREHENSIVE INCOME / (LOSS)

Changes in accumulated other comprehensive income / (loss) by component, net of tax, were as follows:

(In thousands)	Net Gains (Losses) on Cash Flow Hedges	Postretirement Benefits	Total
Balance at December 31, 2012	$ 30,717	$ (6,837)	$ 23,880
Other comprehensive income before reclassifications	32,864		32,864
Amounts reclassified from accumulated other comprehensive income	(10,430)	249	(10,181)
Net current-period other comprehensive income	22,434	249	22,683
Balance at June 30, 2013	$ 53,151	$ (6,588)	$ 46,563

Amounts reclassified from accumulated other comprehensive income / (loss) into the Condensed Consolidated Statement of Operations were as follows:

(In thousands)	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013	Affected Line Item in the Statement Where Net Income is Presented
Net gains / (losses) on cash flow hedges			
Commodity contracts	$ (272)	$ 13,056	Natural gas revenues
Commodity contracts	2,094	4,136	Crude oil and condensate revenues
Postretirement benefits			
Amortization of net loss	(205)	(410)	General and administrative expense
	1,617	16,782	Total before tax
	(636)	(6,601)	Tax (expense) / benefit
Total reclassifications for the period	$ 981	$ 10,181	Net of tax

10. PENSION AND POSTRETIREMENT BENEFITS

The components of net periodic benefit costs, included in general and administrative expense in the Condensed Consolidated Statement of Operations, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2013	2012	2013	2012
Qualified Pension Plan ***(1)***				
Interest cost	$	$ 461	$	$ 922
Expected return on plan assets		(874)		(1,748)
Settlement		7,111		7,111

Amortization of prior service cost				110				221
Amortization of net loss				6,541				13,083
Net periodic pension cost	$		$	13,349	$		$	19,589
Postretirement Benefits								
Service cost	$	415	$	523	$	830	$	1,046
Interest cost		395		418		790		836
Amortization of net loss		205		280		410		560
Total postretirement benefit cost	$	1,015	$	1,221	$	2,030	$	2,442

(1) On July 13, 2012, the Company made a final distribution of benefits from the qualified pension plan.

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11. STOCK-BASED COMPENSATION

Stock-based compensation expense during the first six months of 2013 and 2012 was $28.7 million and $13.1 million, respectively, and is included in general and administrative expense in the Condensed Consolidated Statement of Operations. Stock-based compensation expense in the second quarter of 2013 and 2012 was $10.0 million and $11.4 million, respectively.

Restricted Stock Awards

During the first six months of 2013, 2,050 restricted stock awards were granted to employees with a weighted-average grant date per share value of $68.87. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The Company used an annual forfeiture rate assumption of 6.0% for purposes of recognizing stock-based compensation expense for restricted stock awards.

Restricted Stock Units

During the first six months of 2013, 23,576 restricted stock units were granted to non-employee directors of the Company with a weighted-average grant date per unit value of $53.75. The fair value of these units is measured based on the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and will be issued when the director ceases to be a director of the Company.

Performance Share Awards

During the first six months of 2013, three types of performance share awards were granted to employees for a total of 402,250 performance shares, which included 274,760 performance share awards based on performance conditions measured against the Company s internal performance metrics and 127,490 performance share awards based on market conditions. The Company used an annual forfeiture rate assumption ranging from 0% to 6% for purposes of recognizing stock-based compensation expense for all performance share awards. The performance period for the awards granted in 2013 commenced on January 1, 2013 and ends on December 31, 2015. Refer to Note 12 of the Notes to the Consolidated Financial Statements in the Form 10-K for further description of the various types of performance share awards.

Awards Based on Performance Conditions. The performance awards based on internal metrics had a grant date per share value of $53.23, which is based on the average of the high and low stock price on the grant date. These awards represent the right to receive up to 100% of the award in shares of common stock. Of the 274,760 performance awards based on internal metrics, 84,990 shares have a three-year graded performance period. For these shares, 25% of the shares vest on each of the first and second anniversary dates following the date of the grant and 50% of the shares vest on the third anniversary date following the date of the grant, provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date. If the Company does not meet this metric for the applicable period, then the portion of the performance shares that would have been issued on that anniversary date will be forfeited.

For the remaining 189,770 performance awards, the actual number of shares issued at the end of the performance period will be determined based on the Company s performance against three performance criteria set by the Company s Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria are based on the Company s average production, average finding costs and average reserve replacement over the three-year performance period.

Based on the Company s probability assessment at June 30, 2013, it is considered probable that the criteria for the performance awards based on performance conditions will be met.

Awards Based on Market Conditions. The 127,490 performance shares based on market conditions are earned, or not earned, based on the comparative performance of the Company s common stock measured against fifteen other companies in the Company s peer group over a three-year performance period. These performance shares have both an equity and liability component. The equity portion of the 2013 awards was valued on the grant date (February 21, 2013) and was not marked to market. The liability portion of the awards was valued as of June 30, 2013 on a mark-to-market basis.

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The following assumptions were used to determine the grant date fair value of the equity component and the period-end fair value of the liability component of the Company s performance share awards based on market conditions using a Monte Carlo model:

		Grant Date	June 30, 2013
Value per Share	$	46.12	$46.09 - $70.96
Assumptions:			
Stock Price Volatility		43.8%	31.6% - 43.1%
Risk Free Rate of Return		0.4%	0.1% - 0.5%
Expected Dividend Yield		0.2%	0.1%

Supplemental Employee Incentive Plan

On May 1, 2012, the Company s Board of Directors adopted a new Supplemental Employee Incentive Plan (Plan) to replace the previously adopted supplemental employee incentive plan that expired on June 30, 2012. For further information regarding the terms of the Plan, refer to Note 12 of the Notes to the Consolidated Financial Statements in the Form 10-K. The Company recognized stock-based compensation expense of $1.7 million and $5.1 million for the three and six months ended June 30, 2013, respectively, which is included in general and administrative expense in the Condensed Consolidated Statement of Operations.

On February 11, 2013, the Company achieved the price goal of $50 per share prior to the interim trigger date. Accordingly, a total distribution of approximately $6.8 million was made to the Company s eligible employees under the Plan, of which 25% of the total distribution, or $1.7 million, was paid in February 2013 and the remaining 75%, or $5.1 million, is deferred until August 2014 in accordance with the Plan.

12. ASSET RETIREMENT OBLIGATION

Activity related to the Company s asset retirement obligation is as follows:

(In thousands)		
Balance at December 31, 2012	$	67,016
Liabilities incurred		2,354
Liabilities settled		(757)
Accretion expense		1,777
Balance at June 30, 2013	$	70,390

As of June 30, 2013, approximately $2.0 million, which represents the current portion of the Company s asset retirement obligation, is included in accrued liabilities in the Condensed Consolidated Balance Sheet.

13. Subsequent Event-Stock Split

On July 23, 2013, the Board of Directors declared a 2-for-1 stock split of the Company s common stock in the form of a stock dividend. The stock dividend will be distributed on August 14, 2013 to shareholders of record on August 6, 2013.

The pro forma effect on the June 30, 2013 Condensed Consolidated Balance Sheet is to reduce additional paid-in-capital and increase common stock by $21.1 million, respectively. Pro forma earnings per share and weighted-average shares outstanding, giving retroactive effect to the stock split are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Earnings per share				
Basic as reported (pre-stock split)	$ 0.42	$ 0.17	$ 0.63	$ 0.26
Basic pro forma (post-stock split)	0.21	0.09	0.32	0.13
Diluted as reported (pre-stock split)	0.42	0.17	0.62	0.26
Diluted pro forma (post-stock split)	0.21	0.09	0.31	0.13
Weighted-average shares outstanding				
Basic as reported (pre-stock split)	210,349	209,512	210,250	209,320
Basic pro forma (post-stock split)	420,698	419,024	420,500	418,640
Diluted as reported (pre-stock split)	211,745	211,158	211,492	210,974
Diluted pro forma (post-stock split)	423,490	422,316	422,984	421,948

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cabot Oil & Gas Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Cabot Oil & Gas Corporation and its subsidiaries (the Company) as of June 30, 2013, and the related condensed consolidated statements of operations and of comprehensive income for the three and six month periods ended June 30, 2013 and 2012 and the condensed consolidated statement of cash flows for the six month periods ended June 30, 2013 and 2012. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2012, and the related consolidated statements of operations, comprehensive income, stockholders equity and of cash flows for the year then ended (not presented herein), and in our report dated February 28, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2012, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

July 26, 2013

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ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following review of operations for the three and six month periods ended June 30, 2013 and 2012 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management s Discussion and Analysis included in the Cabot Oil & Gas Corporation Annual Report on Form 10-K for the year ended December 31, 2012 (Form 10-K).

Overview

On an equivalent basis, our production for the six months ended June 30, 2013 increased by 51% compared to the six months ended June 30, 2012. For the six months ended June 30, 2013, we produced 184.5 Bcfe, or 1,019.6 Mmcfe per day, compared to 122.4 Bcfe, or 672.8 Mmcfe per day, for the six months ended June 30, 2012. Natural gas production increased by 60.1 Bcf, or 52%, to 175.8 Bcf for the first six months of 2013 compared to 115.7 Bcf for the first six months of 2012. This increase was primarily the result of increased production in the Marcellus Shale associated with our drilling program and continued expansion of infrastructure in the area. This increase was partially offset by decreases in production in Texas, Oklahoma and West Virginia due to reduced natural gas drilling and normal production declines. Crude oil/condensate/NGL production increased by 323 Mbbls, or 29%, from 1,131 Mbbls in the first six months of 2012 to 1,454 Mbbls in the first six months of 2013. This increase was primarily the result of increased production resulting from our oil-focused drilling program in south Texas and Oklahoma.

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Our average realized natural gas price for the first six months of 2013 was $3.77 per Mcf, 7% higher than the $3.52 per Mcf price realized in the first six months of 2012. Our average realized crude oil price for the first six months of 2013 was $102.65 per Bbl, 3% higher than the $99.76 per Bbl price realized in the first six months of 2012. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to Results of Operations below. Commodity prices are determined by many factors that are outside of our control. Historically, commodity prices have been volatile, and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our capital program, production volumes or future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success.

During the first six months of 2013, we drilled 83 gross wells (69.7 net) with a success rate of 96% compared to 66 gross wells (51.2 net) with a success rate of 99% for the comparable period of the prior year. For the six months ended June 30, 2013, our total capital and exploration spending was $554.1 million compared to $436.5 million for the six months ended June 30, 2012. The increase in capital spending was primarily due to our Marcellus Shale horizontal drilling program in northeast Pennsylvania, the Eagle Ford and Pearsall Shale in south Texas and the Marmaton oil play in Oklahoma. For the full year 2013, we plan to drill approximately 185 to 195 gross wells (155 to 165 net). Our 2013 drilling program includes between $1.1 billion and $1.2 billion in capital and exploration expenditures and is expected to be funded by operating cash flow, existing cash and, if required, borrowings under our credit facility. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the six months ended June 30, 2013 were funds generated from the sale of natural gas and crude oil production (including realizations from our derivative instruments) and net borrowings under our credit facility. These cash flows were primarily used to fund our capital and exploration expenditures and payment of dividends. See below for additional discussion and analysis of cash flow.

Operating cash flow fluctuations are substantially driven by commodity prices, changes in our production volumes and operating expenses. Prices for natural gas and crude oil have historically been and continue to be volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties, as described in our Form 10-K and other filings with the Securities and Exchange Commission, have also influenced prices throughout the recent years. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations for a review of the impact of prices and volumes on revenues.

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Our working capital is also substantially influenced by the variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate availability under our credit facility and liquidity available to meet our working capital requirements.

	Six Months Ended June 30,			
(In thousands)		**2013**		**2012**
Cash flows provided by operating activities	$	489,967	$	291,142
Cash flows used in investing activities		(527,400)		(280,700)
Cash flows provided by financing activities		53,974		8,288
Net increase in cash and cash equivalents	$	16,541	$	18,730

***Operating Activities*.** Net cash provided by operating activities in the first six months of 2013 increased by $198.8 million over the first six months of 2012. This increase was primarily due to higher operating revenues partially offset by higher operating expenses (excluding non-cash expenses) and unfavorable changes in working capital and long-term assets and liabilities. The increase in operating revenues was primarily due to an increase in equivalent production and higher realized natural gas and crude oil prices. Equivalent production volumes increased by 51% for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. Average realized natural gas prices increased by 7% and average realized crude oil prices increased by 3% for the first six months of 2013 compared to the first six months of 2012.

See Results of Operations for additional information relative to commodity price, production and operating expense movements. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. Realized prices may decline in future periods.

***Investing Activities*.** Cash flows used in investing activities increased by $246.7 million for the first six months of 2013 compared to the first six months of 2012. The increase was primarily due to $131.8 million of lower proceeds from sale of assets, an increase of $112.7 million in capital expenditures and an increase of $2.2 million in capital contributions associated with our equity method investment in Constitution Pipeline Company, LLC (Constitution).

***Financing Activities*.** Cash flows provided by financing activities increased by $45.7 million for the first six months of 2013 compared to the first six months of 2012. This increase was primarily due to $33.0 million of higher net borrowings, an increase of $7.3 million in tax benefits associated with our stock-based compensation and a $5.0 decrease in capitalized debt issuance costs.

Effective April 17, 2013, the lenders under our revolving credit facility approved an increase in our borrowing base from $1.7 billion to $2.3 billion as part of the annual redetermination under the terms of the revolving credit facility. The Company s commitments under the credit facility of $900.0 million remained unchanged. At June 30, 2013, we had $380.0 million of borrowings outstanding under our revolving credit facility at a weighted-average interest rate of 2.0% and $519.0 million available for future borrowings.

We were in compliance with all restrictive financial covenants in both the revolving credit facility and senior notes as of June 30, 2013.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash flow from operations, existing cash on hand and availability under our revolving credit facility, if required, we have the capacity to finance our spending plans, service our debt obligations as they become due and maintain our strong financial position.

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Capitalization

Information about our capitalization is as follows:

(Dollars in thousands)		June 30, 2013		December 31, 2012
Debt *(1)*	$	1,142,000	$	1,087,000
Stockholders equity		2,286,241		2,131,447
Total capitalization	$	3,428,241	$	3,218,447
Debt to capitalization		33%		34%
Cash and cash equivalents	$	47,277	$	30,736

(1) Includes $75.0 million of current portion of long-term debt at June 30, 2013 and December 31, 2012 and $380.0 million and $325.0 million of borrowings outstanding under our revolving credit facility at June 30, 2013 and December 31, 2012, respectively.

During the six months ended June 30, 2013, we paid dividends of $8.4 million ($0.04 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant oil and gas property acquisitions, with cash generated from operations and, if necessary, borrowings under our revolving credit facility. We budget these capital and exploration expenditures based on our current estimate of future commodity prices and projected cash flows for the year.

The following table presents major components of capital and exploration expenditures:

	Six Months Ended June 30,			
(In thousands)		2013		2012
Capital expenditures				
Drilling and facilities	$	506,210	$	363,756
Leasehold acquisitions		39,047		47,399
Pipeline and gathering		263		(466)
Other				5,562
		545,520		416,251

Exploration expense		8,553		20,245
Total	$	554,073	$	436,496

For the full year of 2013, we plan to drill approximately 185 to 195 gross wells (155 to 165 net). Our 2013 drilling program includes between $1.1 billion to $1.2 billion in total planned capital and exploration expenditures. See Overview for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment along with our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

Contractual Obligations

We have various contractual obligations in the normal course of our operations. Except for the amended transportation agreements and two new drilling rig commitments described in Note 6 to the Condensed Consolidated Financial Statements included in this Form 10-Q, there have been no material changes to our contractual obligations described under Transportation Agreements , Drilling Rig Commitments and Lease Commitments as disclosed in Note 8 in the Notes to Consolidated Financial Statements and the obligations described under Contractual Obligations in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations included in our Form 10-K.

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Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Form 10-K for further discussion of our critical accounting policies.

Recent Accounting Pronouncements

Effective January 1, 2013, we adopted the amended disclosure requirements prescribed in Accounting Standards Update (ASU) No. 2011-11, Disclosures about Offsetting Assets and Liabilities and ASU No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. This guidance impacted the disclosures associated with our commodity derivatives and did not impact our consolidated financial position, results of operations or cash flows.

Effective January 1, 2013, we adopted the amended disclosure requirements prescribed in ASU No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This guidance impacted our disclosures associated with items reclassified from accumulated other comprehensive income / (loss) and did not impact our consolidated financial position, results of operations or cash flows.

Results of Operations

Second Quarters of 2013 and 2012 Compared

We reported net income in the second quarter of 2013 of $89.1 million, or $0.42 per share, compared to $35.9 million, or $0.17 per share, in the second quarter of 2012. The increase in net income was primarily due to an increase in equivalent production and higher realized natural gas prices, partially offset by higher operating expenses and slightly lower crude oil prices.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Three Months Ended June 30,	Variance

Revenue Variances (In thousands)	2013	2012	Amount	Percent
Natural gas *(1)*	$ 368,391	$ 201,393	$ 166,998	83%
Crude oil and condensate	70,226	57,466	12,760	22%
Brokered natural gas	8,244	5,149	3,095	60%
Other	2,819	1,991	828	42%

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(1) Natural gas revenues exclude the unrealized loss of $0.3 million from the change in fair value of our derivatives not designated as hedges in 2012. There were no unrealized gains or losses in 2013.

	Three Months Ended June 30,		Variance		Increase (Decrease)
	2013	2012	Amount	Percent	(In thousands)
Price Variances					
Natural gas *(1)*	$ 4.06	$ 3.39	$ 0.67	20%	$ 61,075
Crude oil and condensate *(2)*	$ 101.39	$ 102.61	$ (1.22)	(1%)	(840)
Total					$ 60,235
Volume Variances					
Natural gas (Bcf)	90.7	59.2	31.5	53%	$ 105,923
Crude oil and condensate (Mbbl)	693	560	133	24%	13,600
Total					$ 119,523

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(1) These prices include the realized impact of derivative instrument settlements, which increased the price by $1.18 per Mcf in 2012. There was no impact on the realized price from derivative instrument settlements in 2013.

(2) These prices include the realized impact of derivative instrument settlements, which increased the price by $3.02 per Bbl in 2013 and decreased the price by $5.55 per Bbl in 2012.

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Natural Gas Revenues

The increase in natural gas revenues of $167.0 million, excluding the impact of the unrealized losses on derivative instruments discussed above, is primarily due to increased production and higher realized natural gas prices. The increased production was primarily a result of higher production in the Marcellus Shale associated with our drilling program and expanded infrastructure, partially offset by decreases in production primarily in Texas, Oklahoma and West Virginia due reduced natural gas drilling in these areas and normal production declines.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $12.8 million is primarily due to increased production associated with our oil-focused drilling program in south Texas and Oklahoma, partially offset by slightly lower realized oil prices.

Brokered Natural Gas Revenue and Cost

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales price ($/Mcf)	**$** 4.81	$ 2.82	$ 1.99	71%	$ 3,414
Volume brokered (Mmcf)	**x** 1,714	x 1,827	(113)	(6%)	(319)
Brokered natural gas (In thousands)	**$** 8,244	$ 5,149			$ 3,095
Brokered Natural Gas Purchases					
Purchase price ($/Mcf)	**$** 3.91	$ 2.33	$ 1.58	68%	$ (2,717)
Volume brokered (Mmcf)	**x** 1,714	x 1,827	(113)	(6%)	263
Brokered natural gas (In thousands)	**$** 6,704	$ 4,250			$ (2,454)
Brokered natural gas margin (In thousands)	**$** 1,540	$ 899			$ 641

The increase in brokered natural gas margin of $0.6 million is primarily a result of an increase in sales price that outpaced the increase in purchase price, partially offset by lower brokered volumes.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the increase / (decrease) to revenue from the realized impact of cash settlements for derivative instruments designated as cash flow hedges and the net unrealized change in fair value of other financial derivative instruments:

(In thousands)	Three Months Ended June 30, 2013	2012
Cash Flow Hedges		
Natural gas	$ (272)	$ 69,732
Crude oil	2,094	3,110
Other Derivative Financial Instruments		
Natural gas basis swaps		(342)
	$ 1,822	$ 72,500

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Operating and Other Expenses

(In thousands)	Three Months Ended June 30, 2013	2012	Variance Amount	Percent
Operating and Other Expenses				
Direct operations	$ 36,978	29,306	$ 7,672	26%
Transportation and gathering	52,648	33,139	19,509	59%
Brokered natural gas	6,704	4,250	2,454	58%
Taxes other than income	11,364	10,854	510	5%
Exploration	4,529	16,244	(11,715)	(72%)
Depreciation, depletion and amortization	151,389	114,616	36,773	32%
General and administrative	21,608	46,872	(25,264)	(54%)
Total operating expense	$ 285,220	$ 255,281	$ 29,939	12%
(Gain) / loss on sale of assets	$ (276)	$ (67,703)	$ (67,427)	(100%)
Interest expense and other	16,701	18,495	(1,794)	(10%)
Income tax expense	58,921	23,647	35,274	149%

Total costs and expenses from operations increased by $29.9 million, or 12%, in the second quarter of 2013 compared to the same period of 2012. The primary reasons for this fluctuation are as follows:

- Direct operations increased $7.7 million largely due to higher operating costs primarily driven by increased production, including higher treating and disposal costs associated with an increase in produced water and more stringent pipeline quality requirements. In addition, we experienced higher plugging and abandonment costs associated with certain wells in south Texas and a slight increase in outside-operated and employee-related costs due to an increase in headcount.

- Transportation and gathering increased $19.5 million due to higher throughput as a result of increased production, slightly higher transportation rates and the commencement of various transportation and gathering agreements in the second half of 2012 primarily in northeast Pennsylvania and south Texas.

- Brokered natural gas increased $2.5 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

- Exploration expense decreased $11.7 million due to an exploratory dry hole associated with our Brown Dense/Smackover exploratory well in Union County, Arkansas recorded in the second quarter of 2012. There were no dry holes recorded in the second quarter of 2013.

- Depreciation, depletion and amortization increased $36.8 million, of which $55.4 million was due to higher equivalent production volumes for the second quarter of 2013 compared to the second quarter of 2012, partially offset by a decrease of $19.1 million due to a lower

DD&A rate of $1.50 per Mcfe for the second quarter of 2013 compared to $1.71 per Mcfe for the second quarter of 2012. The lower DD&A rate was primarily due to lower cost of reserve additions associated with our 2013 and 2012 drilling programs.

- General and administrative decreased $25.3 million primarily due to $13.3 million of lower pension expense associated with the liquidation of our pension plan that occurred in the second quarter of 2012, a $5.3 million decrease in legal and professional expenses and slightly lower stock-based compensation expense associated with the mark-to-market of our liability-based performance awards and supplemental employee incentive plan due to changes in our stock price for the second quarter 2013 compared to the second quarter of 2012.

(Gain) / Loss on Sale of Assets

The decrease of $67.4 million is primarily due to the gain on sale of certain of our Pearsall Shale undeveloped leaseholds in south Texas recognized in the second quarter of 2012. There were no significant gains or losses on sale of assets recognized in the second quarter of 2013.

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Interest Expense and Other

Interest expense and other decreased $1.8 million primarily due a to lower weighted-average effective interest rate on our revolving credit facility borrowings of approximately 2.2% during the second quarter of 2013 compared to approximately 3.4% during the second quarter of 2012, partially offset by an increase in weighted-average borrowings under our revolving credit facility based on daily balances of approximately $405.7 million during the second quarter of 2013 compared to approximately $293.7 million during the second quarter of 2012.

Income Tax Expense

Income tax expense increased $35.3 million primarily due to higher pretax income. The effective tax rate for the second quarter of 2013 and 2012 was 39.8% and 39.7%, respectively.

First Six Months of 2013 and 2012 Compared

We reported net income in the first six months of 2013 of $131.9 million, or $0.63 per share, compared to $54.3 million, or $0.26 per share, in the first six months of 2012. The increase in net income was primarily due to an increase in equivalent production and higher realized natural gas and crude oil prices partially offset higher operating expenses.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Six Months Ended June 30,		Variance	
Revenue Variances (In thousands)	**2013**	**2012**	**Amount**	**Percent**
Natural gas *(1)*	$ 662,184	$ 408,133	$ 254,051	62%
Crude oil and condensate	135,881	107,447	28,434	26%
Brokered natural gas	19,137	18,593	544	3%
Other	5,763	3,920	1,843	47%

(1) Natural gas revenues exclude the unrealized gain of $0.3 million from the change in fair value of our derivatives not designated as hedges in 2012. There were no unrealized gains or losses in 2013.

Increase

	Six Months Ended June 30, 2013	2012	Variance Amount	Percent	(Decrease) (In thousands)
Price Variances					
Natural gas *(1)*	$ 3.77	$ 3.52	$ 0.25	7%	$ 43,286
Crude oil and condensate *(2)*	$ 102.65	$ 99.76	$ 2.89	3%	3,828
Total					$ 47,114
Volume Variances					
Natural gas (Bcf)	175.8	115.7	60.1	52%	$ 210,765
Crude oil and condensate (Mbbl)	1,324	1,077	247	23%	24,606
Total					$ 235,371

(1) *These prices include the realized impact of derivative instrument settlements, which increased the price by $0.07 per Mcf in 2013 and by $1.10 per Mcf in 2012.*

(2) *These prices include the realized impact of derivative instrument settlements, which increased the price by $3.12 per Bbl in 2013 and decreased the price by $1.66 per Bbl in 2012.*

Natural Gas Revenues

The increase in natural gas revenues of $254.1 million, excluding the impact of the unrealized losses on derivative instruments discussed above, is primarily due to increased production during the first six months of 2013 and higher realized natural gas prices. The increased production was primarily a result of higher production in the Marcellus Shale associated with our drilling program and expanded infrastructure, partially offset by decreases in production primarily in Texas, Oklahoma and West Virginia due reduced natural gas drilling in these areas and normal production declines.

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Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $28.4 million is primarily due to increased production associated with our oil-focused drilling program in south Texas and Oklahoma and higher realized oil prices.

Brokered Natural Gas Revenue and Cost

	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012		Variance Amount		Variance Percent		Price and Volume Variances (In thousands)
Brokered Natural Gas Sales									
Sales price ($/Mcf)	**$**	4.00	$	3.62	$	0.38	11%	$	1,836
Volume brokered (Mmcf)	**x**	4,781	x	5,138		(357)	(7%)		(1,292)
Brokered natural gas (In thousands)	**$**	19,137	$	18,593				$	544
Brokered Natural Gas Purchases									
Purchase price ($/Mcf)	**$**	3.16	$	3.14	$	0.02	1%	$	(91)
Volume brokered (Mmcf)	**x**	4,781	x	5,138		(357)	(7%)		1,120
Brokered natural gas (In thousands)	**$**	15,093	$	16,122				$	1,029
Brokered natural gas margin (In thousands)	**$**	4,044	$	2,471				$	1,573

The increased brokered natural gas margin of $1.6 million is primarily a result of an increase in sales price that outpaced the increase in purchase price, partially offset by lower brokered volumes.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the increase / (decrease) to revenue from the realized impact of cash settlements for derivative instruments designated as cash flow hedges and the net unrealized change in fair value of other financial derivative instruments:

(In thousands)		Six Months Ended June 30, 2013		Six Months Ended June 30, 2012
Cash Flow Hedges				
Natural Gas	**$**	13,056	$	126,728
Crude Oil		4,136		1,784

Other Financial Derivative Instruments				
Natural Gas Basis Swaps				(300)
	$	17,192	$	128,212

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Operating and Other Expenses

(In thousands)	Six Months Ended June 30, 2013	2012	Variance Amount	Percent
Operating and Other Expenses				
Direct operations	$ 68,475	$ 56,626	$ 11,849	21%
Transportation and gathering	98,869	63,397	35,472	56%
Brokered natural gas	15,093	16,122	(1,029)	(6%)
Taxes other than income	23,051	29,437	(6,386)	(22%)
Exploration	8,553	20,245	(11,692)	(58%)
Depreciation, depletion and amortization	300,042	224,973	75,069	33%
General and administrative	57,312	69,421	(12,109)	(17%)
Total operating expense	$ 571,395	$ 480,221	$ 91,174	19%
(Gain) / loss on sale of assets	$ (180)	$ (67,168)	$ (66,988)	(100%)
Interest expense and other	32,956	35,412	(2,456)	(7%)
Income tax expense	86,856	35,073	51,783	148%

Total costs and expenses from operations increased by $91.2 million, or 19%, in the first six months of 2013 compared to the same period of 2012. The primary reasons for this fluctuation are as follows:

- Direct operations increased $11.8 million largely due to higher operating costs primarily driven by increased production, including higher treating and disposal costs associated with an increase in produced water and more stringent pipeline quality requirements. In addition, we experienced higher plugging and abandonment costs associated with certain wells in south Texas and an increase in outside-operated costs. Partially offsetting these increases was a decrease in workover activity.

- Transportation and gathering increased $35.5 million due to higher throughput as a result of increased production, slightly higher transportation rates and the commencement of various transportation and gathering agreements in the second half of 2012 primarily in northeast Pennsylvania and south Texas.

- Brokered natural gas decreased $1.0 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

- Taxes other than income decreased $6.4 million primarily due to lower impact fees associated with our Marcellus Shale production partially offset by higher production taxes. The second quarter of 2012 included the initial assessment of impact fees associated with 2011 and prior period wells.

- Exploration expense decreased $11.7 million due to an exploratory dry hole associated with our Brown Dense/Smackover exploratory well in Union County, Arkansas recorded in the first six months of 2012. There were no dry holes recorded in the first six months of

2013.

- Depreciation, depletion and amortization increased $75.1 million, of which $105.3 million was due to higher equivalent production volumes for the first six months of 2013 compared to the first six months of 2012, partially offset by a decrease of $29.7 million due to a lower DD&A rate of $1.53 per Mcfe for the first six months of 2013 compared to $1.70 per Mcfe for the first six months of 2012. The lower DD&A rate was primarily due to lower cost of reserve additions associated with our 2013 and 2012 drilling programs.

- General and administrative decreased $12.1 million primarily due $19.6 million of lower pension expense associated with the liquidation of our pension plan that occurred in the first six months of 2012 and $5.1 million of lower legal and professional expenses, partially offset by $15.6 million of higher stock-based compensation expense associated with the mark-to-market of our liability-based performance awards and our supplemental employee incentive plan due to changes in our stock price for the first six months of 2013 compared to the first six months of 2012.

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(Gain) / Loss on Sale of Assets

The decrease of $67.0 million is primarily due to the gain on sale of certain of our Pearsall Shale undeveloped leaseholds in south Texas recognized in the first six months of 2012. There were no significant gains or losses on sale of assets recognized in the first six months of 2013.

Interest Expense and Other

Interest expense and other decreased $2.5 million primarily due a to lower weighted-average effective interest rate on our revolving credit facility borrowings of approximately 2.3% during the first six months of 2013 compared to approximately 3.7% during the first six months of 2012, partially offset by an increase in weighted-average borrowings under our revolving credit facility based on daily balances of approximately $383.8 million during the first six months of 2013 compared to approximately $263.2 million during the first six months of 2012.

Income Tax Expense

Income tax expense increased $51.8 million primarily due to higher pretax income and a slightly higher effective tax rate. The effective tax rate for the first six months of 2013 and 2012 was 39.7% and 39.3%, respectively.

Forward-Looking Information

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, forecast, predict, may, should, could, will and similar expressions are forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and crude oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See Risk Factors in Item 1A of the Form 10-K for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Market Risk

Our primary market risk is exposure to crude oil and natural gas prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 13 of the Notes to the Consolidated Financial Statements in our Form 10-K for a more detailed discussion of our hedging arrangements.

Periodically, we enter into commodity derivative instruments, including collar and swap agreements, to hedge our exposure to price fluctuations on natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity hedges other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk management purposes and are not held for trading purposes. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under the swap agreements, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

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As of June 30, 2013, we had the following outstanding commodity derivatives:

				Collars					
				Floor		Ceiling		Swaps	Estimated Fair Value Asset (Liability)
Period and Type of Contract	**Volume**		**Contract Period**	**Range *(1)***	**Weighted Average *(1)***	**Range *(1)***	**Weighted Average *(1)***	**(Weighted Average) *(1)***	**(In thousands)**
Natural gas collars	8.9	Bcf	Jul. 2013 - Dec. 2013	$	$ 5.15	$ 6.18-$6.23	$ 6.20		$ 16,790
Natural gas collars	109.0	Bcf	Jul. 2013 - Dec. 2013	$ 3.09-$4.37	$ 3.63	$ 3.98-$5.02	$ 4.27		21,444
Natural gas collars	53.3	Bcf	Jul. 2013 - Dec. 2014	$ 3.60-$3.96	$ 3.78	$ 4.55-$4.59	$ 4.57		6,320
Natural gas collars	124.1	Bcf	Jan. 2014 - Dec. 2014	$ 3.86-$4.37	$ 4.19	$ 4.63-$4.80	$ 4.70		39,568
Crude oil swaps	552	Mbbl	Jul. 2013 - Dec. 2013					$ 101.90	3,733
									$ 87,855

(1) *Natural gas prices are stated per Mcf and crude oil prices are stated per barrel.*

The amounts set forth under the estimated fair value column in the table above represent our total unrealized net gain position at June 30, 2013 and exclude the impact of nonperformance risk. Nonperformance risk is primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our nonperformance risk is evaluated using a market credit spread provided by one of our banks.

During the first six months of 2013, crude oil swaps covered 543 Mbbl, or 41% of crude oil production at an average price of $101.90 per Bbl. Natural gas collars with a floor prices ranging from $3.09 to $5.15 per Mcf and ceiling prices ranging from $3.98 to $6.23 per Mcf covered 105.9 Bcf, or 60.2%, of our natural gas production at an average price of $4.01 per Mcf.

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of nonperformance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to nonperformance by third parties. Our derivative contract counterparties are Bank of America, Bank of Montreal, Goldman Sachs, JPMorgan Chase, and Morgan Stanley.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See Forward-Looking Information for further details.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated amount we would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes and credit facility is based on interest rates currently available to us.

We use available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	June 30, 2013		December 31, 2012	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**