Rosetta Resources Inc.
Form 10-Q
August 04, 2014
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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

¨ **Transition Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
Commission File Number: 000-51801

ROSETTA RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**43-2083519**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1111 Bagby Street, Suite 1600 Houston, TX	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 335-4000

(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 (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 ¨

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 ¨

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 definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

The number of shares of the registrant s Common Stock, $0.001 par value per share, outstanding as of July 25, 2014 was 61,481,038 which excludes unvested restricted stock awards.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	June 30, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 28,194	$ 193,784
Accounts receivable	137,518	122,677
Derivative instruments		4,307
Prepaid expenses	7,186	9,860
Deferred income taxes	25,016	27,976
Other current assets	4,604	1,284
Total current assets	202,518	359,888
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	4,937,235	3,951,397
Unproved/unevaluated properties, not subject to amortization	511,762	755,438
Gathering systems and compressor stations	262,424	168,730
Other fixed assets	28,316	26,362
	5,739,737	4,901,927
Accumulated depreciation, depletion and amortization, including impairment	(2,185,100)	(2,020,879)
Total property and equipment, net	3,554,637	2,881,048
Other assets:		
Debt issuance costs	29,050	25,602
Derivative instruments		5,458
Other long-term assets	326	4,622
Total other assets	29,376	35,682
Total assets	$ 3,786,531	$ 3,276,618
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 252,674	$ 190,950
Royalties and other payables	94,166	78,264

Derivative instruments	33,742	4,913
Total current liabilities	380,582	274,127
Long-term liabilities:		
Derivative instruments	21,368	433
Long-term debt	1,800,000	1,500,000
Deferred income taxes	159,968	136,407
Other long-term liabilities	21,015	17,317
Total liabilities	2,382,933	1,928,284
Commitments and Contingencies (Note 9)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2014 or 2013		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 62,260,461 shares and 62,032,162 shares at June 30, 2014 and December 31, 2013, respectively	62	61
Additional paid-in capital	1,190,788	1,182,672
Treasury stock, at cost; 781,843 shares and 724,755 shares at June 30, 2014 and December 31, 2013, respectively	(27,138)	(24,592)
Accumulated other comprehensive loss	(102)	(108)
Retained earnings	239,988	190,301
Total stockholders equity	1,403,598	1,348,334
Total liabilities and stockholders equity	$ 3,786,531	$ 3,276,618

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues:				
Oil sales	$ 162,703	$ 102,895	$ 294,380	$ 212,947
NGL sales	55,442	46,918	110,737	93,379
Natural gas sales	52,140	40,657	103,519	74,233
Derivative instruments	(49,395)	46,050	(73,180)	34,081
Total revenues	220,890	236,520	435,456	414,640
Operating costs and expenses:				
Lease operating expense	25,064	11,217	44,585	20,128
Treating and transportation	18,618	18,520	39,295	33,607
Taxes, other than income	12,259	8,735	22,465	16,390
Depreciation, depletion and amortization	90,640	47,837	165,415	92,467
General and administrative costs	21,667	18,508	41,205	34,040
Total operating costs and expenses	168,248	104,817	312,965	196,632
Operating income	52,642	131,703	122,491	218,008
Other expense (income):				
Interest expense, net of interest capitalized	17,327	13,033	32,617	19,102
Interest income	(1)		(13)	
Other expense	12,496	471	12,647	441
Total other expense	29,822	13,504	45,251	19,543
Income before provision for income taxes	22,820	118,199	77,240	198,465
Income tax expense	8,376	42,847	27,553	69,633
Net income	$ 14,444	$ 75,352	$ 49,687	$ 128,832
Earnings per share:				
Basic	$ 0.24	$ 1.28	$ 0.81	$ 2.31
Diluted	$ 0.23	$ 1.27	$ 0.81	$ 2.29
Weighted average shares outstanding:				

Basic	61,452	58,990	61,416	55,879
Diluted	61,617	59,201	61,599	56,165

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Comprehensive Income

(In thousands)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Net income	$ 14,444	$ 75,352	$ 49,687	$ 128,832
Other comprehensive income (loss):				
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of ($1) and ($155) for the three and six months ended June 30, 2013, respectively		1		272
Postretirement medical benefits prior service benefit (cost), net of income taxes of ($2) and ($3) for the three months ended June 30, 2014 and 2013, respectively, ($4) and $101 for the six months ended June 30, 2014 and 2013, respectively	3	6	6	(179)
Other comprehensive income (loss)	3	7	6	93
Comprehensive income	$ 14,447	$ 75,359	$ 49,693	$ 128,925

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Cash flows from operating activities:		
Net income	$ 49,687	$ 128,832
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	165,415	92,467
Deferred income taxes	26,521	67,890
Amortization of deferred loan fees recorded as interest expense	1,900	6,827
Loss on debt extinguishment	3,101	
Stock-based compensation expense	7,393	4,893
Loss (gain) due to change in fair value of derivative instruments	59,529	(28,790)
Change in operating assets and liabilities:		
Accounts receivable	(14,840)	(12,330)
Prepaid expenses	2,578	668
Other current assets	(3,320)	63
Long-term assets	46	
Accounts payable and accrued liabilities	(15,041)	8,412
Royalties and other payables	15,901	12,140
Other long-term liabilities	810	3,164
Excess tax benefit from share-based awards		(2,697)
Net cash provided by operating activities	299,680	281,539
Cash flows from investing activities:		
Acquisitions of oil and gas assets	(79,020)	(940,982)
Additions to oil and gas assets	(675,835)	(345,606)
Disposals of oil and gas assets	8	(1,724)
Net cash used in investing activities	(754,847)	(1,288,312)
Cash flows from financing activities:		
Borrowings on Credit Facility	550,000	420,000
Payments on Credit Facility	(550,000)	(440,000)
Issuance of Senior Notes	500,000	700,000
Retirement of Senior Notes	(200,000)	
Proceeds from issuance of common stock		329,152
Deferred loan fees	(8,354)	(18,004)

Proceeds from stock options exercised	376	2,674
Purchases of treasury stock	(2,546)	(6,723)
Excess tax benefit from share-based awards	101	2,697
Net cash provided by financing activities	289,577	989,796
Net decrease in cash	(165,590)	(16,977)
Cash and cash equivalents, beginning of period	193,784	36,786
Cash and cash equivalents, end of period	$ 28,194	$ 19,809
Supplemental disclosures:		
Capital expenditures included in Accounts payable and accrued liabilities	$ 195,400	$ 94,001

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

(Unaudited)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	Accumulated Other Comprehensive Loss	Retained Earnings	Total Stockholders Equity
Balance at December 31, 2013	62,032,162	$ 61	$ 1,182,672	724,755	$ (24,592)	$ (108)	$ 190,301	$ 1,348,334
Excess tax benefit from share-based awards			101					101
Stock options exercised	19,000	1	376					377
Treasury stock employee tax payment				57,088	(2,546)			(2,546)
Stock-based compensation			7,639					7,639
Vesting of restricted stock	209,299							
Comprehensive income						6	49,687	49,693
Balance at June 30, 2014	62,260,461	$ 62	$ 1,190,788	781,843	$ (27,138)	$ (102)	$ 239,988	$ 1,403,598

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements (unaudited)

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company s operations are located in the Eagle Ford shale in South Texas and the Permian Basin in West Texas.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. (GAAP). These financial statements and notes should be read in conjunction with the Company s audited Consolidated Financial Statements and the notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2013 (2013 Annual Report).

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2013 Annual Report. There have been no changes to the Company s significant accounting policies since December 31, 2013.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers. The ASU will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the Company expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures sufficient to enable users to understand an entity s nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The pronouncement is effective for annual and interim reporting periods beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. This guidance is not expected to have a material impact on the Company s consolidated financial position, results of operations, or cash flows.

(3) Property and Equipment

The Company s Total property and equipment, net consists of the following:

	June 30, 2014	December 31, 2013
	(In thousands)	

Proved properties	$ 4,937,235	$ 3,951,397
Unproved/unevaluated properties	511,762	755,438
Gathering systems and compressor stations	262,424	168,730
Other fixed assets	28,316	26,362
Total	5,739,737	4,901,927
Less: Accumulated depreciation, depletion and amortization	(2,185,100)	(2,020,879)
Total property and equipment, net	$ 3,554,637	$ 2,881,048

Acquisitions

2014 Permian Acquisition. On December 30, 2013, the Company entered into a definitive agreement with several private parties to acquire Delaware Basin assets covering 5,034 net acres located in Reeves County (the 2014 Permian Acquisition). These assets include 13 gross producing wells, of which 11 are operated by the Company. The Company completed the 2014 Permian Acquisition on February 28, 2014, with an effective date of December 1, 2013, for total cash consideration of $83.2 million, subject to further customary post-closing adjustments.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells along with a third party s option to participate in future wells in certain leases of its Gates Ranch leasehold located in the Eagle Ford shale (the Gates Acquisition) in Webb County for total cash consideration of approximately $128.1 million. The transaction closed on June 5, 2013 (the Gates Acquisition Date) and was financed with borrowings under the Company s senior secured revolving credit facility (the Credit Facility), as described in Note 7 Debt and Credit Agreements. As of the Gates Acquisition Date, the Company owns a 100% working interest in the entire Gates Ranch leasehold.

2013 Permian Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP to purchase producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas (the 2013 Permian Acquisition). The Company completed the 2013 Permian Acquisition on May 14, 2013, with an effective date of January 1, 2013, for total cash consideration of $825.2 million. The 2013 Permian Acquisition was financed with the proceeds from the Company s issuance of the 5.625% Senior Notes, as described in Note 7 Debt and Credit Agreements, and the common stock offering described in Note 10 Equity. In connection with the 2013 Permian Acquisition and related financings, the Company incurred total transaction costs of approximately $31.0 million, including (i) $5.6 million of commitment fees and related expenses associated with a bridge credit facility (Bridge Credit Facility), which were recorded as Interest expense since the Company did not borrow under the Bridge Credit Facility, (ii) $10.0 million of debt issuance costs paid in connection with the issuance of the 5.625% Senior Notes, which were deferred and are being amortized over the term of these senior notes, (iii) $13.1 million of equity issuance costs and related expenses associated with the common stock offering, which were reflected as a reduction of equity proceeds, and (iv) $2.3 million of consulting, investment, advisory, legal and other acquisition-related fees, which were expensed and are included in General and administrative costs.

The above transactions were accounted for under the acquisition method of accounting, whereby each respective purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (or shortfall of purchase price versus net fair value recorded as bargain purchase). Based on the final purchase price allocations for the Gates Acquisition and the 2013 Permian Acquisition and the preliminary purchase price allocation for the 2014 Permian Acquisition, no goodwill or bargain purchase was recognized. The final purchase price allocation for the 2013 Permian and Gates Ranch Acquisitions and the preliminary purchase price allocation for the 2014 Permian Acquisition, representing consideration paid, assets acquired and liabilities assumed as of the respective acquisition dates, are shown in the tables below.

2014 Permian Acquisition

	Preliminary Total Purchase Price Allocation (In thousands)
Cash consideration	$ 83,172
Fair value of assets acquired:	
Oil and natural gas properties	
Proved properties	$ 61,598
Unproved/unevaluated properties	21,867
Total assets acquired	$ 83,465

Fair value of liabilities assumed:		
Asset retirement obligations	$	293
Net assets acquired	$	83,172

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2013 Permian Acquisition and Gates Ranch Acquisition

	Final Total Purchase Price Allocation (In thousands)	
Cash consideration	$	953,242
Fair value of assets acquired:		
Other fixed assets	$	600
Oil and natural gas properties		
Proved properties		290,273
Unproved/unevaluated properties		663,300
Total assets acquired	$	954,173
Fair value of liabilities assumed:		
Asset retirement obligations	$	931
Net assets acquired	$	953,242

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by the Company s management at the time of the valuation and are the most sensitive and subject to change. See Note 5 Fair Value Measurements for additional information.

The results of operations attributable to the 2014 Permian Acquisition were included in the Company s Consolidated Statement of Operations beginning on March 1, 2014 and increased Total revenues by $4.4 million and $5.9 million, respectively, and Operating income by $1.7 million and $2.3 million, respectively, for the three and six months ended June 30, 2014.

The following unaudited pro forma information assumes the transactions and related financings for the 2013 Permian Acquisition and the Gates Acquisition occurred on January 1, 2012 and the 2014 Permian Acquisition occurred on January 1, 2013. The unaudited pro forma information includes the effects of issuing the 5.625% Senior Notes, the issuance of common stock in the equity offering and the use of proceeds from the debt and equity offerings as discussed above. The pro forma results of operations have been prepared by adjusting the Company s historical results to include the historical results of the acquired assets based on information provided by the seller, the Company s knowledge of the acquired properties and the impact of the Company s purchase price allocation. The Company believes the assumptions used provide a reasonable basis for reflecting the pro forma significant effects directly attributable to the acquisitions and associated financings. The pro forma results of operations do not include any cost savings or other synergies that may result from the acquisitions, or any estimated costs that have been or will be incurred by the Company to integrate these assets. The pro forma information does not purport to represent what the Company s results of operations would have been if the 2013 Permian Acquisition and Gates Acquisition had occurred on January 1, 2012 and the 2014 Permian Acquisition had occurred on January 1, 2013.

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	Three Months Ended June 30, 2014 (1)	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014 (2)	Six Months Ended June 30, 2013
	(In thousands, except per share and share data)		(In thousands, except per share and share data)	
Total revenues	$ 220,890	$ 254,986	$ 438,553	$ 457,901
Net income	14,444	73,625	50,480	126,350
Earnings per share:				
Basic	$ 0.24	$ 1.21	$ 0.82	$ 2.07
Diluted	$ 0.23	$ 1.20	$ 0.82	$ 2.06
Weighted average shares outstanding:				
Basic	61,452	61,094	61,416	60,939
Diluted	61,617	61,305	61,599	61,226

(1) No pro forma adjustments were made for the period as all acquisitions and related financings are included in the Company s historical results.

(2) No pro forma adjustments were made related to the 2013 Permian Acquisition and Gates Acquisition for the period as the acquisitions are included in the Company s historical results.

Additional Disclosures about Property and Equipment

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $2.1 million and $1.8 million of internal costs for the three months ended June 30, 2014 and 2013, respectively, and $3.7 million and $3.9 million for the six months ended June 30, 2014 and 2013, respectively.

Oil and gas properties include unevaluated property costs of $511.8 million and $755.4 million as of June 30, 2014 and December 31, 2013, respectively, which are not being amortized. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest. Such costs are periodically evaluated for impairment, and upon evaluation or impairment are transferred to the Company s full cost pool and amortized. During the six months ended June 30, 2014, the Company transferred $147.9 million of Permian acquisition costs to the full cost pool as a result of development activities in this area.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company s costs are included in one cost center because all of the Company s operations are located in the United States. The Company s ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of June 30, 2014, which were based on a West Texas Intermediate oil price of $96.75 per Bbl and a Henry Hub natural gas price of $4.10 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and natural gas properties as of June 30, 2014, and as a result, no write-down was recorded. It is possible that a write-down of the Company s oil and gas properties could occur in future periods in the event that oil and natural gas prices significantly decline or the Company experiences significant downward adjustments to its estimated proved reserves.

(4) Commodity Derivative Contracts

The Company is exposed to various market risks, including volatility in oil, natural gas liquids (NGL) and natural gas prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company s oil, NGL and natural gas production.

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As of June 30, 2014, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2014	Costless Collar	3,000	552,000	$ 83.33	$ 109.63
Crude oil	2014	Swap	6,000	1,104,000	93.13	
Crude oil	2015	Swap	11,000	4,015,000	89.51	
Crude oil	2016	Swap	6,000	2,196,000	90.28	
				7,867,000		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2014	Swap	4,500	828,000	$ 13.21
NGL-Propane	2014	Swap	2,785	512,440	44.71
NGL-Isobutane	2014	Swap	930	171,120	61.26
NGL-Normal Butane	2014	Swap	875	161,000	60.29
NGL-Pentanes Plus	2014	Swap	910	167,440	84.97
NGL-Ethane	2015	Swap	2,500	912,500	11.59
NGL-Propane	2015	Swap	1,250	456,250	43.26
NGL-Isobutane	2015	Swap	450	164,250	53.76
NGL-Normal Butane	2015	Swap	400	146,000	53.76
NGL-Pentanes Plus	2015	Swap	400	146,000	76.44
				3,665,000	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (MMBtu)	Total Notional Volume (MMBtu)	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2014	Costless Collar	50,000	9,200,000	3.60	4.94
Natural gas	2015	Costless Collar	50,000	18,250,000	3.60	5.04
Natural gas	2016	Costless Collar	40,000	14,640,000	3.50	5.58
Natural gas	2014	Swap	30,000	5,520,000	4.07	
Natural gas	2015	Swap	40,000	14,600,000	4.18	
Natural gas	2016	Swap	30,000	10,980,000	4.04	
				73,190,000		

As of June 30, 2014, the Company s derivative instruments were with counterparties who are lenders under its Credit Facility. This practice allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit Facility, thus eliminating the need for independent collateral postings. The Company s ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Items 1 and 2. Business and Properties Government Regulation in the Company s 2013 Annual Report. As of June 30, 2014, the Company had no deposits for collateral regarding commodity derivative positions.

Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company elected to de-designate all commodity contracts previously designated as cash flow hedges as of December 31, 2011 and discontinue hedge accounting prospectively. As of December 31, 2013, all frozen mark-to-market values included in Accumulated other comprehensive income were reclassified into earnings. With the election to de-designate hedging instruments, all of the Company s derivative instruments are recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in Accumulated other comprehensive income. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but such adjustments had no cash flow impact in the current period. The cash flow impact occurs upon settlement of the underlying contract.

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Additional Disclosures about Derivative Instruments

Authoritative derivative guidance requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company s financial statements. The following table sets forth information on the location and amounts of the Company s derivative instrument fair values in the Consolidated Balance Sheet as of June 30, 2014 and December 31, 2013, respectively:

		Asset (Liability) Fair Value	
		June 30, 2014	December 31, 2013
Commodity derivative contracts	**Location on Consolidated Balance Sheet**	(In thousands)	
Oil	Derivative instruments current assets	$	$ 1,299
Oil	Derivative instruments non-current assets		2,117
Oil	Derivative instruments current liabilities	(29,703)	(5,629)
Oil	Derivative instruments non-current liabilities	(18,449)	
NGL	Derivative instruments current assets		2,834
NGL	Derivative instruments non-current assets		(129)
NGL	Derivative instruments current liabilities	(282)	461
NGL	Derivative instruments non-current liabilities	(1,100)	(433)
Natural gas	Derivative instruments current assets		174
Natural gas	Derivative instruments non-current assets		3,470
Natural gas	Derivative instruments current liabilities	(3,757)	255
Natural gas	Derivative instruments non-current liabilities	(1,819)	
Total derivative fair value, net, not designated as hedging instruments		$ (55,110)	$ 4,419

The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the three and six months ended June 30, 2014 and 2013, respectively:

Location on Consolidated Statement of Operations	**Description of (Loss) Gain**	**Three Months Ended June 30, 2014**	**2013**	**Six Months Ended June 30, 2014**	**2013**
		(In thousands)			
Derivative instruments	(Loss) gain recognized in income	(5,714)	3,289	(13,651)	5,291
	Realized (loss) gain recognized in income	$ (5,714)	$ 3,289	$ (13,651)	$ 5,291
Derivative instruments	(Loss) gain recognized in income due to changes in fair value	$ (43,681)	$ 42,763	$ (59,529)	$ 29,217
Derivative instruments	Loss reclassified from Accumulated OCI		(2)		(427)

Unrealized (loss) gain recognized in income	$ (43,681)	$ 42,761	$ (59,529)	$ 28,790
Total commodity derivative (loss) gain recognized in income	$ (49,395)	$ 46,050	$ (73,180)	$ 34,081

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(5) Fair Value Measurements

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. See Note 3 Property and Equipment for more information on the Company s fair value measurement of non-recurring assets and liabilities related to the 2014 Permian Acquisition.

As defined in the guidance of the Financial Accounting Standards Board (FASB), fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The FASB s guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

The following table sets forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis for the respective period:

	Fair value as of June 30, 2014				
	Level 1	Level 2	Level 3	Netting (1)	Total
			(In thousands)		
Assets:					
Money market funds	$	$ 1,035	$	$	$ 1,035
Commodity derivative contracts			8,986	(8,986)	

	Level 1	Level 2	Level 3	Netting (1)	Total
Liabilities:					
Commodity derivative contracts			(64,096)	8,986	(55,110)
Total fair value	$	$ 1,035	$ (55,110)	$	$ (54,075)

	Fair value as of December 31, 2013				
	Level 1	Level 2	Level 3 (In thousands)	Netting (1)	Total
Assets:					
Money market funds	$	$ 1,035	$	$	$ 1,035
Commodity derivative contracts			21,675	(11,910)	9,765
Liabilities:					
Commodity derivative contracts			(17,256)	11,910	(5,346)
Total fair value	$	$ 1,035	$ 4,419	$	$ 5,454

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle. No margin or collateral balances are deposited with counterparties and as such, gross amounts are offset to determine the net amounts presented in the Consolidated Balance Sheet.

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The Company s Level 3 instruments include commodity derivative contracts for which fair value is determined by a third-party provider. Although the Company compares the fair values derived from the third-party provider with its counterparties, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its third-party provider or counterparties. Therefore, these commodity derivative contracts are classified as Level 3 instruments.

The following table presents a range of the unobservable inputs provided by the Company s third-party provider utilized in the fair value measurements of the Company s assets and liabilities classified as Level 3 instruments as of June 30, 2014 (in thousands):

Level 3 Instrument	Asset (Liability) (In thousands)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average
Oil swaps	$ (47,633)	Discounted cash flow	Forward price curve-swaps	$ 90.08	$ 105.17	$ 96.98
Oil costless collars	(520)	Option model	Forward price curve-costless collar option value	(2.30)	0.34	0.94
NGL swaps	2,509	Discounted cash flow	Forward price curve-swaps	0.29	1.36	0.59
NGL swaps	(3,890)	Discounted cash flow	Forward price curve-swaps	0.28	2.21	0.94
Natural gas swaps	(4,779)	Discounted cash flow	Forward price curve-swaps	3.97	4.59	4.27
Natural gas costless collars	21	Option model	Forward price curve-costless collar option value	(0.22)	0.16	0.00
Natural gas costless collars	(818)	Option model	Forward price curve-costless collar option value	(0.30)	0.24	0.03
Total	$ (55,110)					

The determination of derivative fair values by the third-party provider incorporates a credit adjustment for nonperformance risk, including the credit standing of the counterparties involved, and the impact of the Company s nonperformance risk on its liabilities. The Company recorded an upward adjustment to the fair value of its derivative instruments in the amount of $1.3 million as of June 30, 2014.

The significant unobservable inputs for Level 3 derivative contracts include forward price curves and option values. Significant increases (decreases) in the quoted forward prices for commodities and option values generally lead to corresponding decreases (increases) in the fair value measurement of the Company s oil, NGL and natural gas derivative contracts.

The tables below present reconciliations of financial assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods.

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		Derivative Asset (Liability) (In thousands)
Balance at January 1, 2014	$	4,419
Total Gains or (Losses) (Realized or Unrealized):		
Included in Earnings		(73,180)
Purchases, Issuances and Settlements:		
Settlements		13,651
Transfers in and out of Level 3		
Balance at June 30, 2014	$	(55,110)

		Derivative Asset (Liability) (In thousands)
Balance at January 1, 2013	$	20,664
Total Gains or (Losses) (Realized or Unrealized):		
Included in Earnings		34,508
Purchases, Issuances and Settlements:		
Settlements		(5,291)
Transfers in and out of Level 3		
Balance at June 30, 2013	$	49,881

Fair Value of Other Financial Instruments

All of the Company s other financial instruments (excluding derivatives) are presented on the balance sheet at carrying value. As of June 30, 2014, the carrying value of cash and cash equivalents (excluding money market funds), other current assets and current liabilities reported in the Consolidated Balance Sheet approximate fair value because of their short-term nature, and all such financial instruments are considered Level 1 instruments.

The Company s debt consists of publicly traded Senior Notes (defined below). The fair values of the Company s Senior Notes are based upon unadjusted quoted market prices and are considered Level 1 instruments. As of June 30, 2014, the carrying amount of total debt was $1.80 billion and the estimated fair value of total debt was $1.87 billion.

(6) Asset Retirement Obligations

The following table provides a rollforward of the Company s asset retirement obligations (ARO). Liabilities incurred during the period include additions to obligations and obligations incurred from acquisitions. Liabilities settled during the period include settlement payments for obligations. Activity related to the Company s ARO is as follows:

	Six Months Ended June 30, 2014 (In thousands)

ARO as of December 31, 2013	$	13,057
Liabilities incurred during period		2,334
Liabilities settled during period		
Accretion expense		495
ARO as of June 30, 2014	$	15,886

As of June 30, 2014, the $4.0 million current portion of the total ARO is included in Accrued liabilities, and the $11.9 million long-term portion of ARO is included in Other long-term liabilities on the Consolidated Balance Sheet.

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(7) Debt and Credit Agreements

Senior Secured Revolving Credit Facility. On April 2, 2014, the Company entered into the Omnibus Eighth Amendment to Amended and Restated Senior Revolving Credit Agreement (the Amendment) with Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto. The Amendment, among other things, (i) authorized the redemption of the Company s 9.500% Senior Notes due 2018 (the 9.500% Senior Notes), (ii) increased the borrowing base from $800.0 million to $950.0 million and (iii) reconfirmed the committed amount under the Credit Facility at $800 million with a maximum credit amount of $1.5 billion.

As of June 30, 2014, the Company had no amounts outstanding with $800.0 million of available borrowing capacity under its Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% and mature in April 2018. Additionally, the Company can borrow under the Credit Facility at the Alternative Base Rate (ABR), which is based upon the Prime Rate in effect on such day plus a margin of 0.5% to 1.5% depending on the Company s utilization percentage. The weighted average borrowing rate under the Credit Facility for the three and six months ended June 30, 2014 was 2.65% and 2.38%, respectively, exclusive of commitment fees. For the three and six months ended June 30, 2014, interest expense was $0.9 million and $1.0 million, respectively, and commitment fees were $0.6 million and $1.4 million, respectively, under the Credit Facility. Borrowings under the Credit Facility are collateralized by liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of the Company s domestic subsidiaries and a pledge of 100% of the membership and limited partnership interests of the Company s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is also subject to certain financial covenants, including the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. As of June 30, 2014, the Company s current ratio was 2.9 and leverage ratio was 2.8. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales and liens on properties.

9.500% Senior Notes due 2018. In accordance with the provisions of the indenture governing the Company s 9.500% Senior Notes, on May 5, 2014, the Company redeemed all of the outstanding notes in full at a price of 104.75% of the principal amount, plus accrued and unpaid interest. The Company paid an aggregate amount of $210.6 million for such redemption, consisting of a call premium of $9.5 million and $1.1 million of accrued and unpaid interest. The call premium of $9.5 million and remaining unamortized debt issuance costs of $3.1 million are included in Other expense in the Company s Consolidated Statement of Operations in the second quarter of 2014.

5.625% Senior Notes due 2021. On May 2, 2013, the Company completed its public offering of $700.0 million in aggregate principal amount of 5.625% Senior Notes due 2021 (the 5.625% Senior Notes). Interest is payable on the 5.625% Senior Notes semi-annually on May 1 and November 1. The 5.625% Senior Notes were issued under an indenture (the Base Indenture), as supplemented by a first supplemental indenture (as so supplemented, the 5.625% Senior Notes Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the 5.625% Senior Notes Indenture limit the Company s ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company s restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The 5.625% Senior Notes Indenture also contains customary events of default.

5.875% Senior Notes due 2022. On November 15, 2013, the Company completed its public offering of $600.0 million in aggregate principal amount of 5.875% Senior Notes due 2022 (the 5.875% Senior Notes due 2022). Interest is payable on the 5.875% Senior Notes due 2022 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2022 were issued under the Base Indenture, as supplemented by a second supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture.

5.875% Senior Notes due 2024. On May 29, 2014, the Company completed its public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024 (the 5.875% Senior Notes due 2024 and, together with the 5.625% Senior Notes and the 5.875% Senior Notes due 2022, the Senior Notes). Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2024 were issued under the Base Indenture, as supplemented by a third supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture.

Total Indebtedness. As of June 30, 2014, the Company had total outstanding borrowings of $1.80 billion, and for the six months ended June 30, 2014, the Company s weighted average borrowing rate was 6.04%, inclusive of interest and commitment fees.

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(8) Income Taxes

The Company s effective tax rate for the three and six months ended June 30, 2014 was 36.7% and 35.7%, respectively, and the effective tax rate for the three and six months ended June 30, 2013 was 36.2% and 35.1%, respectively. The provision for income taxes for the three and six months ended June 30, 2014 differs from the tax computed at the federal statutory income tax rate primarily due to the impact of state income taxes and the non-deductibility of certain incentive compensation. As of June 30, 2014 and December 31, 2013, the Company had no unrecognized tax benefits. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of June 30, 2014, the Company had a net deferred tax liability of $135.0 million resulting primarily from the differences between the book basis and tax basis of the Company s oil and natural gas properties, partially offset by net operating loss carryforwards.

(9) Commitments and Contingencies

Firm Oil and Natural Gas Transportation and Processing Commitments. The Company has commitments for the transportation and processing of its production in the Eagle Ford area and has an aggregate minimum commitment to deliver 5.3 MMBbls of oil by the end of 2017 and 612 million MMBtus of natural gas by mid-year 2028. The Company is required to make periodic deficiency payments for any shortfalls in delivering the minimum volumes under these commitments. Currently, the Company has insufficient production to meet all of these contractual commitments. As the Company develops additional reserves in the Eagle Ford area, it anticipates exceeding its current minimum volume commitments and therefore intends to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments could expose the Company to additional volume deficiency payments. As of June 30, 2014, the Company has accrued deficiency fees of $4.1 million and expects to continue to accrue deficiency fees under its commitments. Future obligations under firm oil and natural gas transportation and processing agreements as of June 30, 2014 are as follows:

	June 30, 2014 (In thousands)
2014	$ 10,352
2015	22,818
2016	22,132
2017	21,708
2018	18,159
Thereafter	102,406
Total future obligations	$ 197,575

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors to execute the Company s Eagle Ford and Permian Basin drilling programs. As of June 30, 2014, the Company had three outstanding drilling rig commitments with terms greater than one year that will expire by the end of 2016, and the minimum contractual commitments due in the next twelve months were $21.8 million. Payments under these commitments are accounted for as capital additions to oil and gas properties. As of June 30, 2014, the Company s minimum contractual commitments due in the next twelve months for completion services agreements for the stimulation, cementing and delivery of drilling fluids and other field service commitments were $9.4 million. Payments under these commitments are accounted for as capital additions to oil and gas properties or as Lease operating expense, depending on the nature of the related expenditures.

Contingencies. The Company is party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability the Company may ultimately incur with respect to any such proceeding may be in excess of amounts currently accrued, if any. After considering the Company s available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, the Company does not believe any such matter will have a material adverse effect on its financial position, results of operations or cash flows.

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(10) Equity

Earnings per Share. Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted-average number of shares of common stock (excluding unvested restricted stock awards) outstanding during the period (the denominator). Diluted EPS incorporates the dilutive impact of outstanding stock options and unvested restricted stock awards using the treasury stock method.

The following is a calculation of basic and diluted weighted average shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Basic weighted average number of shares outstanding	61,452	58,990	61,416	55,879
Dilution effect of stock option and restricted shares at the end of the period	165	211	183	286
Diluted weighted average number of shares outstanding	61,617	59,201	61,599	56,165
Anti-dilutive stock awards and shares		6	5	2

Common Stock Offering. On April 23, 2013, the Company completed its public offering of 7,000,000 shares of common stock at a price to the public of $42.50 per share for net proceeds of approximately $286.3 million ($40.80 per share, net of underwriting discounts and commissions), including offering expenses and reimbursements by the underwriters of certain expenses incurred in connection with the offering. The Company also received net proceeds of approximately $43.0 million in connection with the underwriters full exercise of their over-allotment option to purchase 1,050,000 additional shares of common stock, which closed on April 29, 2013.

(11) Stock-Based Compensation and Employee Benefits

Stock-based compensation expense includes the expense associated with restricted stock granted to employees and directors and the expense associated with the Performance Share Units (PSUs) granted to management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Total stock-based compensation expense	$ 4,158	$ 2,303	$ 7,639	$ 5,041
Capitalized in oil and gas properties	(123)	(74)	(246)	(148)
Net stock-based compensation expense	$ 4,035	$ 2,229	$ 7,393	$ 4,893

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All stock-based compensation expense associated with restricted stock granted to employees and directors is recognized on a straight-line basis over the applicable remaining vesting period. For the three and six months ended June 30, 2014, the Company recorded compensation expense of approximately $2.3 million and $5.0 million, respectively, related to these equity awards. As of June 30, 2014, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $15.9 million.

Stock-based compensation expense associated with the PSUs granted to management is recognized over a three-year performance period. For the three and six months ended June 30, 2014, the Company recognized compensation expense of $1.8 million and $2.6 million, respectively, associated with the PSUs. At the current fair value as of June 30, 2014, and assuming the Board elects the maximum available payout of 200% for all PSU metrics, unrecognized stock-based compensation expense related to the PSUs was approximately $20.2 million. The Company s total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company s performance, expected payout and quarter-end closing common stock prices. For a more detailed description of the Company s PSU plans, including related performance conditions and structure, see the definitive proxy statement filed with respect to the Company s 2014 annual meeting under the heading Compensation Discussion and Analysis and the Company s 2013 Annual Report.

Postretirement Health Care. Effective January 1, 2013, the Company enacted a postretirement medical benefit plan covering eligible employees and their eligible dependents. Upon enactment, the Company recognized a $0.3 million liability related to the prior service of employees, which is included as a component of Other comprehensive income. The Company recognizes periodic postretirement benefits cost as a component of General and administrative costs. For both the three and six months ended June 30, 2014, this expense was immaterial.

(12) Guarantor Subsidiaries

The Company s Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several. In addition, there are no restrictions on the ability of the Company to obtain funds from its subsidiaries by dividend or loan. Finally, none of the Company s subsidiaries has restricted assets that exceed 25% of net assets as of the most recent fiscal year which may not be transferred to the Company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements regarding the Company within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, would, expect, pl project, intend, anticipate, believe, estimate, forecast, predict, potential, pursue, target or continu such terms or variations thereon, or other comparable terminology. Unless the context clearly indicates otherwise, references in this report to Rosetta, the Company, we, our, us or like terms refer to Rosetta Resources Inc. and it subsidiaries.

The forward-looking statements contained in this report reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2013 (the 2013 Annual Report). We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- our ability to maintain leasehold positions that require exploration and development activities and material capital expenditures;

- unexpected difficulties in integrating our operations as a result of any significant acquisitions;

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- the supply and demand for oil, NGLs and natural gas;
- changes in the price of oil, NGLs and natural gas;
- general economic conditions, either internationally, nationally or in jurisdictions where we conduct business;
- conditions in the energy and financial markets;
- our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;
- the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program and/or lease operating expenses;
- failure of joint interest partners to pay us our share of revenue;
- the occurrence of property acquisitions or divestitures;
- reserve levels;
- inflation or deflation;
- competition in the oil and natural gas industry;
- the availability and cost of relevant raw materials, equipment, goods, services and personnel;
- changes or advances in technology;
- potential reserve revisions;

the availability and cost, as well as limitations and constraints on infrastructure required, to gather, transport, process and market oil, NGLs and natural gas;

performance of contracted markets and companies contracted to provide transportation, processing and trucking of oil, NGLs and natural gas;

developments in oil-producing and natural gas-producing countries;

drilling, completion, production and facility risks;

exploration risks;

legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, changes in national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, environmental regulations and environmental risks and liability under federal, state and local environmental laws and regulations;

effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

present and possible future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;

the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;

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factors that could impact the cost, extent and pace of executing our capital program, including but not limited to, access to oilfield services, access to water for hydraulic fracture stimulations and permitting delays, unavailability of required permits, lease suspensions, drilling, exploration and production moratoriums and other legislative, executive or judicial actions by federal, state and local authorities, as well as actions by private citizens, environmental groups or other interested persons;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers;

electronic, cyber or physical security breaches; and

any other factors that impact or could impact the exploration and development of oil, NGLs or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil, NGLs and natural gas.

Overview

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 and material changes in our financial condition since December 31, 2013. This discussion should be read in conjunction with our 2013 Annual Report, which includes disclosures regarding our critical accounting policies as part of Management s Discussion and Analysis of Financial Condition and Results of Operations.

Results for the three months ended June 30, 2014 include the following:

production of 61.5 MBoe/d compared to 48.8 MBoe/d for the three months ended June 30, 2013;

34 gross (32.7 net) operated wells drilled compared to 30 gross (30 net) operated wells drilled for the three months ended June 30, 2013; and

net income of $14.4 million, or $0.23 per diluted share, compared to $75.4 million, or $1.27 per diluted share, for the three months ended June 30, 2013.

Results for the six months ended June 30, 2014 include the following:

production of 57.9 MBoe/d compared to 47.9 MBoe/d for the six months ended June 30, 2013;

81 gross (79.2 net) operated wells drilled compared to 54 gross (53.2 net) operated wells drilled for the six months ended June 30, 2013; and

net income of $49.7 million, or $0.81 per diluted share, compared to $128.8 million, or $2.29 per diluted share, for the six months ended June 30, 2013.

Our principal operating and business strategy is focused on the acquisition, development and production of oil, NGLs and natural gas from unconventional resource plays. Our operations are primarily located in the Eagle Ford area in South Texas and in the Delaware Basin in West Texas, two of the most active unconventional resource plays in the United States.

Rosetta is a significant producer in the liquids-rich window of the Eagle Ford region and we have established an inventory of high-return drilling opportunities that offer predictable and long-term production, reserve growth and a more valuable commodity mix. Our Permian Basin assets and bolt-on activity further expand our portfolio of long-lived, oil-rich resource projects that will drive our long-term growth and sustainability. During the first quarter of 2014, we acquired additional Delaware Basin assets from several private parties for total cash consideration of $83.2 million, subject to further customary post-closing adjustments. The acquisition covered 5,034 net acres located in Reeves County. The acquired assets included 13 gross producing wells (11 operated) and added future horizontal drilling locations to expand our capital project inventory. We will continue to consider investments in the Eagle Ford shale region, Permian Basin and other unconventional resource basins that offer a viable inventory of projects, including resource-based exploration projects, producing property acquisitions in early development stages and acreage swaps.

Our current development operations in the Eagle Ford shale are primarily focused in several areas. Our original discovery in 2009 is located in the 26,230-acre Gates Ranch leasehold in Webb County. We are also active in the Briscoe Ranch lease in Dimmit County, three leases located in the Central Dimmit County area and the Tom Hanks lease in northern LaSalle County, where our positions were delineated in 2011, 2012 and 2013, respectively. In addition, we are evaluating new venture growth opportunities with several pilot wells testing the Upper Eagle Ford. Overall, we hold 63,000 net acres in the region with approximately 50,000 acres located in the liquids producing portions of the play. Our operations in the Permian are focused in Reeves County in the Delaware Basin where we are testing multiple benches in the Wolfcamp and 3rd Bone Spring. Currently, we hold 47,000 net acres in the Delaware Basin and approximately 13,000 net exploratory acres in the Midland Basin.

The ongoing development of our assets in South Texas, which averaged approximately 57.0 MBoe/d for the three months ended June 30, 2014, an increase of 21 percent from the prior year, has contributed to record liquids volumes for the Company. Production from the Permian averaged approximately 4.5 MBoe/d in the second quarter, an increase of six percent from the first quarter of 2014, adding to our higher valued crude oil mix. For the three months ended June 30, 2014, approximately 65 percent of our production was from liquids as compared to 62 percent for the same period in 2013. The Eagle Ford area accounted for approximately 92 percent of our total production for the three months ended June 30, 2014. In addition, crude oil and NGLs represented approximately 63 percent of the production from the Eagle Ford area and 90 percent of production from the Permian.

We drilled 34 gross operated wells and completed 37 gross operated wells during the quarter ended June 30, 2014. Of these totals, 21 wells were drilled and 28 completed in the Eagle Ford area. In the Delaware Basin, 13 gross operated wells were successfully drilled, including eight horizontal and five vertical wells. A total of nine gross operated wells were completed, five of which were horizontal wells. As of June 30, 2014, we had completed a total of 272 gross wells in the Eagle Ford shale since entering the play in 2009. Since initiating our Permian operations in August 2013, we have completed nine horizontal wells through the end of the second quarter.

In the second quarter of 2014, total daily equivalent production reached an all-time high of 61.5 MBoe/d, an increase of 26 percent from the same period in 2013, and 13 percent growth from the prior quarter. For the same period, total daily crude oil production was 19.0 MBbls/d, an increase of 56 percent from the same period in 2013 and 18 percent growth from the prior quarter. To handle our increased production, we have multiple options for transportation and processing capacity with firm commitments and other arrangements in place to meet total planned production levels through 2015. We executed an agreement to increase Eagle Ford gross takeaway capacity by 100 MMcf/d to 345 MMcf/d by the fourth quarter of 2014. We will continue to evaluate adding more firm capacity in our operating areas.

Our 2014 capital program is expected to total $1.2 billion, excluding capital used to fund the 2014 Permian Acquisition. The 2014 program is based on a four to five-rig Eagle Ford program and a five to six-rig Permian program, including four rigs dedicated to horizontal drilling. Approximately $790 million, or 66 percent of our 2014 capital program, will be spent on development activities in the Eagle Ford shale in South Texas, including about $125 million allocated to central facilities projects for our planned 2014 and 2015 well programs. Approximately $320 million, or 27 percent, will be spent on activities in the Delaware Basin in West Texas. In addition, the 2014 budget allocates approximately $90 million for other capital items, including evaluation of new venture opportunities, capitalized interest and other corporate capital.

While our unconventional resource strategy has proven to be successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Although we cannot completely control all external factors that could affect our operating environment, our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. We have diversified our production base to include a greater mix of crude oil and NGLs, which are priced at more favorable levels than natural gas. Because our production is highly concentrated geographically, we have taken various steps to provide access to necessary services and infrastructure. We believe that our 2014 capital program can be executed from internally generated cash flows, cash on hand and borrowings under our Credit Facility. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs. If our internal funds are insufficient to meet projected funding requirements, we would consider curtailing capital spending or accessing the capital markets.

Availability under our Credit Facility is restricted to a borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on hedging arrangements and asset divestitures. The amount of the borrowing base is dependent on a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. As of June 30, 2014, we had no borrowings outstanding with $800 million available for borrowing under the Credit Facility. On May 5, 2014, we redeemed our 9.500% Senior Notes with borrowings under the Credit Facility for a total payment of $210.6 million, which includes the principal amount, a call premium and accrued and unpaid interest. On May 29, 2014, we completed our public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024. Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1.

Results of Operations

Revenues

Our consolidated financial statements for the three months ended June 30, 2014 reflect total revenues of $220.9 million (including derivative losses of $49.4 million) based on total volumes of 5.6 MMBoe. Our consolidated financial statements for the six months ended June 30, 2014 reflect total revenues of $435.5 million (including derivative losses of $73.2 million) based on total volumes of 10.5 MMBoe.

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The following table summarizes the components of our revenues for the periods indicated, as well as each period s production volumes and average realized prices:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change Increase/ (Decrease)	2014	2013	% Change Increase/ (Decrease)
Revenues (in thousands):						
Oil sales	$ 162,703	$ 102,895	58%	$ 294,380	$ 212,947	38%
NGL sales	55,442	46,918	18%	110,737	93,379	19%
Natural gas sales	52,140	40,657	28%	103,519	74,233	39%
Derivative instruments	(49,395)	46,050	(207%)	(73,180)	34,081	(315%)
Total revenues	$ 220,890	$ 236,520	(7%)	$ 435,456	$ 414,640	5%
Production:						
Oil (MBbls)	1,731	1,109	56%	3,184	2,226	43%
NGLs (MBbls)	1,931	1,655	17%	3,601	3,144	15%
Natural gas (MMcf)	11,583	10,081	15%	22,165	19,820	12%
Total equivalents (MBoe)	5,593	4,444	26%	10,479	8,674	21%
Daily Production:						
Oil (MBbls/d)	19.0	12.2	56%	17.6	12.3	43%
NGLs (MBbls/d)	21.2	18.2	16%	19.9	17.4	14%
Natural gas (MMcf/d)	127.3	110.8	15%	122.5	109.5	12%
Total equivalents (MBoe/d)	61.5	48.8	26%	57.9	47.9	21%
Average sales price:						
Oil, excluding derivatives (per Bbl)	$ 93.99	$ 92.78	1%	$ 92.46	$ 95.66	(3%)
Oil, including realized derivatives (per Bbl)	90.88	91.75	(1%)	89.84	94.20	(5%)
NGL, excluding derivatives (per Bbl)	28.71	28.35	1%	30.75	29.70	4%
NGL, including realized derivatives (per Bbl)	29.20	31.12	(6%)	30.21	31.97	(6%)
Natural gas, excluding derivatives (per Mcf)	4.50	4.03	12%	4.67	3.75	25%
Natural gas, including realized derivatives (per Mcf)	4.39	4.02	9%	4.52	3.82	18%
Revenue, excluding derivatives (per Boe)	48.33	42.86	13%	48.54	43.87	11%
Revenue, including realized derivatives (per Boe)	47.30	43.60	8%	47.24	44.48	6%

Oil sales. For the three and six months ended June 30, 2014, oil sales, excluding the effect of derivative instruments, increased by $59.8 million and $81.4 million, respectively, from the same periods in 2013. For the three months ended

June 30, 2014, the 6.8 MBbls/d increase in oil production resulted in a $57.8 million increase in oil sales, and an increase in the average sales price for oil increased oil sales by $2.0 million. The increase in oil production was primarily attributable to a 3.2 MBbls/d increase resulting from our continued development in the Tom Hanks lease and a 2.4 MBbls/d increase resulting from our growth and development in the Permian Basin. For the six months ended June 30, 2014, the 5.3 MBbls/d increase in oil production resulted in a $91.6 million increase in oil sales, which was partially offset by a $10.2 million decrease due to a lower average sales price for oil. The increase in oil production was primarily attributable to a 2.8 MBbls/d increase resulting from our entry into the Permian Basin and a 2.0 MBbls/d increase resulting from our continued development in the Tom Hanks lease.

Oil derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and six months ended June 30, 2014, realized oil derivative losses were $5.4 million and $8.3 million, respectively, compared to realized oil derivative losses of $1.1 million and $3.3 million for the three and six months ended June 30, 2013, respectively.

NGL sales. For the three and six months ended June 30, 2014, NGL sales, excluding the effect of derivative instruments, increased by $8.5 million and $17.4 million, respectively, from the same periods in 2013. For the three months ended June 30, 2014, the 3.0 MBbls/d increase in NGL production resulted in a $7.8 million increase in NGL sales, and an increase in the average sales price for NGLs increased NGL sales by $0.7 million. The increase in NGL production was primarily attributable to an increase of 3.2 MBbls/d from the Briscoe Ranch area as a result of our continued development activities in that area as well as a 0.3 MBbls/d increase resulting from our growth and development in the Permian Basin. For the six months ended June 30, 2014, the 2.5 MBbls/d increase in NGL production resulted in a $13.6 million increase in NGL sales, and an increase in the average sales price for NGLs increased NGL sales by $3.8 million. The increase in NGL production was primarily attributable to an increase of 2.3 MBbls/d from the Briscoe Ranch area as a result of our continued development activities in that area as well as a 0.4 MBbls/d increase resulting from our entry into the Permian Basin.

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NGL derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and six months ended June 30, 2014, we realized an NGL derivative gain of $1.0 million and a loss of $1.9 million, respectively, compared to realized NGL derivative gains of $4.6 million and $7.2 million for the three and six months ended June 30, 2013, respectively.

Natural gas sales. For the three and six months ended June 30, 2014, natural gas sales, excluding the effect of derivative instruments, increased by $11.5 million and $29.3 million, respectively, from the same periods in 2013. For the three months ended June 30, 2014, the 16.5 MMcf/d increase in natural gas production resulted in a $6.1 million increase in natural gas sales, and an increase in the average sales price for natural gas increased natural gas sales by $5.4 million. The increase in natural gas production was primarily attributable to development activities at Briscoe Ranch and the Encinal area, where natural gas production increased by 17.3 MMcf/d and 3.8 MMcf/d, respectively, partially offset by a decline at Gates Ranch of 6.4 MMcf/d. For the six months ended June 30, 2014, the 13.0 MMcf/d increase in natural gas production resulted in an $8.8 million increase in natural gas sales, and an increase in the average sales price for natural gas increased natural gas sales by $20.5 million. The increase in natural gas production was primarily attributable to development activities at Briscoe Ranch and the Encinal area, where natural gas production increased by 12.5 MMcf/d and 3.8 MMcf/d, respectively, partially offset by a decline at Gates Ranch of 5.1 MMcf/d.

Natural gas derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and six months ended June 30, 2014, realized natural gas derivative losses were $1.3 million and $3.4 million, respectively, compared to a realized natural gas derivative loss of $0.2 million and a gain of $1.4 million, respectively, for the three and six months ended June 30, 2013.

Derivative instruments. For the three and six months ended June 30, 2014, Derivative instruments included (i) unrealized derivative losses of $43.7 million and $59.5 million, respectively, due to changes in the fair value of our commodity derivative contracts, and (ii) realized derivative losses of $5.7 million and $13.7 million, respectively, from cash settlements associated with our commodity derivative contracts.

For the three and six months ended June 30, 2013, Derivative instruments included (i) unrealized derivative gains of $42.8 million and $29.2 million, respectively, due to changes in the fair value of our commodity derivative contracts, (ii) the reclassification of unrealized derivative losses of an immaterial amount and $0.4 million, respectively, from Accumulated other comprehensive income and (iii) realized derivative gains of $3.3 million and $5.3 million, respectively, from cash settlements associated with our commodity derivative contracts.

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Operating Expenses

The following table summarizes our production costs and operating expenses for the periods indicated:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change Increase/ (Decrease)	2014	2013	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Direct lease operating expense	$ 14,768	$ 11,055	34%	$ 30,554	$ 19,409	57%
Insurance expense	312	154	103%	581	357	63%
Workover expense	9,984	8	124700%	13,450	362	3615%
Lease operating expense (Production costs)	$ 25,064	$ 11,217	123%	$ 44,585	$ 20,128	122%
Treating and transportation	18,618	18,520	1%	39,295	33,607	17%
Taxes, other than income	12,259	8,735	40%	22,465	16,390	37%
Depreciation, depletion and amortization (DD&A)	90,640	47,837	89%	165,415	92,467	79%
General and administrative costs	21,667	18,508	17%	41,205	34,040	21%
Costs and expenses (per Boe of production)						
Lease operating expense (Production costs)	$ 4.48	$ 2.52	78%	$ 4.25	$ 2.32	83%
Treating and transportation	3.33	4.17	(20%)	3.75	3.87	(3%)
Taxes, other than income	2.19	1.97	11%	2.14	1.89	13%
Depreciation, depletion and amortization (DD&A)	16.21	10.76	51%	15.79	10.66	48%
General and administrative costs	3.87	4.16	(7%)	3.93	3.92	0%
General and administrative costs, excluding stock-based compensation	3.15	3.66	(14%)	3.23	3.36	(4%)

Lease operating expense. Lease operating expense increased $13.8 million and $24.5 million for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended June 30, 2014 was the result of increased Eagle Ford operations, which contributed $11.1 million of the increase, including $6.2 million of incremental well workover costs, and the 2013 Permian Acquisition, which represented $4.0 million of the increase, including $3.8 million of incremental well workover costs. These increases were partially offset by a decline in costs of $1.3 million primarily due to the suspension of drilling programs in non-core areas. The increase for the six months ended June 30, 2014 was the result of increased Eagle Ford operations, which contributed $15.9 million of the increase, including $8.4 million of incremental well workover costs, and the 2013 Permian Acquisition, which represented $10.8 million of the increase, including $4.9 million of incremental well workover costs. These increases were partially offset by a decline in costs of $2.2 million primarily due to the suspension of drilling programs in non-core areas.

Treating and transportation. Treating and transportation expense increased $0.1 million and $5.7 million for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013. While daily production increased in both core areas, expense for the three months ended June 30, 2014 remained flat primarily due to the utilization of lower-cost transportation and processing primarily in the Eagle Ford area. The increase for the six months ended June 30, 2014 was primarily due to the utilization of higher-cost transportation and processing during the first quarter of 2014 to deliver production in the Eagle Ford shale, and the addition of Permian production in 2014. Additionally, we have accrued deficiency fees of $2.3 million and $4.1 million related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during the three and six months ended June 30, 2014, respectively.

Taxes, other than income. Taxes, other than income include production taxes and ad valorem taxes. Production taxes are based on revenues generated from production, and ad valorem taxes are based on the valuation of the underlying assets. Taxes, other than income increased $3.5 million and $6.1 million for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended June 30, 2014 was the result of a 12.7 MBoe/d increase in production, which represented $2.2 million of the increase, and a $0.22 per Boe increase in unit costs, which represented $1.3 million of the increase. These higher unit costs resulted from our continued shift toward higher-value oil production as well as the availability of fewer tax incentives for oil-directed wells. The increase for the six months ended June 30, 2014 was the result of a 10.0 MBoe/d increase in production, which represented $3.4 million of the increase, and a $0.25 per Boe increase in unit costs, which represented $2.7 million of the increase.

Depreciation, depletion and amortization. DD&A expense increased $42.8 million and $72.9 million for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013. The increases were a result of increased depletion rates due to the inclusion of higher-cost Permian reserves in our depletion pool, as well as increased daily production of 26% and 21%, respectively.

General and administrative costs. General and administrative costs increased $3.2 million and $7.2 million for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended June 30, 2014 was primarily due to a $3.6 million increase in personnel costs, partially offset by a $0.6 million decrease in rent expense. The increase for the six months ended June 30, 2014 was primarily due to a $7.7 million increase in personnel costs, partially offset by a $1.1 million decrease in rent expense.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense, increased $16.3 million and $25.7 million for the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The increases were primarily due to a $9.5 million call premium and the write-off of $3.1 million of remaining unamortized debt issuance costs associated with the redemption of our 9.500% Senior Notes, an increase in debt outstanding compared to the prior comparable period and higher weighted average interest rates, partially offset by higher capitalized interest. The weighted average interest rates, inclusive of interest and commitment fees, for the three and six months ended June 30, 2014 were 5.83% and 6.04%, respectively, compared to 5.83% and 5.63%, respectively, for the same periods in 2013.

Provision for Income Taxes

The effective tax rate for the three and six months ended June 30, 2014 was 36.7% and 35.7%, respectively, and the effective tax rate for the three and six months ended June 30, 2013 was 36.2% and 35.1%, respectively. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the effects of state taxes and the non-deductibility of certain incentive compensation. As of June 30, 2014 and December 31, 2013, we had no unrecognized tax benefits and we do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next twelve months.

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of June 30, 2014, we had a net deferred tax liability of $135.0 million resulting primarily from differences between the book basis and tax basis of our oil and natural gas properties, partially offset by net operating loss carryforwards.

Liquidity and Capital Resources

Our sources of liquidity and capital are our operating cash flow, our cash on hand and our Credit Facility, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising commodity prices. The effects of these derivative transactions on our oil, NGL and natural gas sales are discussed above under Results of Operations Revenues. The majority of our capital expenditures is discretionary and could be curtailed if our cash flows materially decline from expected levels. Economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program or accessing the capital markets.

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Cash Flows

The following table presents information regarding the change in our cash flows:

	Six Months Ended June 30, 2014	2013
	(In thousands)	
Cash provided by (used in):		
Operating activities	$ 299,680	$ 281,539
Investing activities	(754,847)	(1,288,312)
Financing activities	289,577	989,796
Net decrease in cash and cash equivalents	$ (165,590)	$ (16,977)

Operating Activities. The increase in net cash provided by operating activities for the six months ended June 30, 2014 compared to the same period in 2013 reflects increased production and more favorable NGL and natural gas prices.

Investing Activities. The reduction in net cash used in investing activities for the six months ended June 30, 2014 compared to the same period in 2013 reflects a reduction in our acquisition activity, partially offset by higher capital spending related to our Eagle Ford drilling program and further development in the Permian Basin.

Financing Activities. The reduction in net cash provided by financing activities for the six months ended June 30, 2014 compared to the same period in 2013 reflects a reduction in debt and equity issuances, along with the redemption of our 9.500% Senior Notes in 2014.

Capital Expenditures and Requirements

Our historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2013 Annual Report and is incorporated herein by reference.

Excluding acquisitions, our accrual-basis capital expenditures for the six months ended June 30, 2014 increased by $403.8 million to $753.1 million from $349.3 million for the six months ended June 30, 2013. During the six months ended June 30, 2014, we drilled 81 and completed 91 gross wells, the majority of which are located in the Eagle Ford area. Excluding capital used to fund the 2014 Permian Acquisition, our capital budget for 2014 is projected to be $1.2 billion.

We have the discretion to use availability under the Credit Facility to fund capital expenditures. We also have the ability to adjust our capital expenditure plans throughout the remainder of the year in response to market conditions.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps and costless collars for each year through 2016. Our fixed price swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on a portion of our anticipated production upon inception of the derivative instruments. See Note 4 Commodity Derivative Contracts and Note 5 Fair Value Measurements included in Part I. Item 1. Financial Statements of this Form 10-Q for a listing of open contracts as of June 30, 2014, a description of the applicable accounting and the estimated fair market values as of June 30, 2014. The effects of material changes in market risk exposure associated with these derivative transactions are discussed below under Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Governmental Regulation

There have been no material changes in governmental regulations that impact our business from those previously disclosed in our 2013 Annual Report.

Critical Accounting Policies and Estimates

Management makes many estimates and assumptions in the application of GAAP that may have a material impact on our consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. All such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on information available prior to the issuance of the financial statements. Changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates. There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2013 Annual Report.

Recent Accounting Developments

For a discussion of recent accounting developments, see Note 2 Summary of Significant Accounting Policies included in Part I. Item 1. Financial Statements of this Form 10-Q.

Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is our belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

As noted in Note 9 Commitments and Contingencies included in Part I. Item 1. Financial Statements of this Form 10-Q, we forecast long-term production from the development of our reserves in the Eagle Ford area. These forecasts are used to identify our future transportation and processing volume requirements. Based on these forecasts, we have secured additional firm capacity for the transportation and processing of our production in the Eagle Ford area. These commitments are typically effective prior to us having sufficient current production to meet the minimum volume commitments, and we are therefore required to make periodic deficiency payments for delivering less than the minimum required volumes. As we develop additional reserves in the Eagle Ford area, we anticipate exceeding our current minimum volume commitments, and we therefore intend to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments in the Eagle Ford area could expose us to additional volume deficiency payments and as of June 30, 2014, we have accrued deficiency fees of $4.1 million. As of June 30, 2014, we had no such commitments in the Permian area, but as these assets are developed and additional firm capacity for the transportation and processing of our production is added, we could be subject to periodic deficiency payments.

We are party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, we do not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk primarily related to adverse changes in oil, NGL and natural gas prices. We use derivative instruments to manage our commodity price risk caused by fluctuating prices. We do not enter into derivative instruments for trading purposes. For information regarding our exposure to certain market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2013 Annual Report and Note 4 Commodity Derivative Contracts included in Part I. Item 1. Financial Statements of this Form 10-Q.

As of June 30, 2014, we had open crude oil derivative contracts in a net liability position with a fair value of $48.2 million. A 10% increase in crude oil prices would reduce the fair value by approximately $73.3 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $71.2 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

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As of June 30, 2014, we had open NGL derivative contracts in a net liability position with a fair value of $1.4 million. A 10% increase in NGL prices would reduce the fair value by approximately $12.8 million, while a 10% decrease in NGL prices would increase the fair value by approximately $12.8 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of June 30, 2014, we had open natural gas derivative contracts in a net liability position with a fair value of $5.6 million. A 10% increase in natural gas prices would reduce the fair value by approximately $20.3 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $20.1 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

These transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than anticipated, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement or the counterparties to our derivative agreements fail to perform under the contracts.

As of June 30, 2014, our derivative instruments are with counterparties who are lenders under our Credit Facility. This practice allows us to satisfy any need for margin obligations resulting from an adverse change in the fair market value of the derivative contracts with the collateral securing our Credit Facility, thus eliminating the need for independent collateral postings. As of June 30, 2014, we had no deposits for collateral regarding commodity derivative positions. Our derivative instrument assets and liabilities relate to commodity hedges that represent the difference between hedged prices and future market prices on hedged volumes of the commodities as of June 30, 2014. Our third-party provider evaluated nonperformance risk using the current credit default swap values or bond spreads for both the counterparties and us. We recorded an upward adjustment to the fair value of our derivative instruments in the amount of $1.3 million as of June 30, 2014. We are not aware of any circumstances which currently exist that would limit access to our Credit Facility or require a change in our debt or hedging structure.

We entered into oil, NGL and natural gas derivative contracts with respect to a portion of our anticipated production through 2016. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices exceed the prices established by the contracts. As of June 30, 2014, 72% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 28% at Light Louisiana Sweet; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 73% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, 23% at Tennessee, zone 0 and the remaining 4% at Henry Hub.

We use a third-party provider to determine the valuation of our derivative instruments and compare the fair values derived from the third-party provider with values provided by our counterparties. We mark-to-market the fair values of our derivative instruments on a quarterly basis, and 100% of our derivative assets and liabilities are considered Level 3 instruments.

Item 4. Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of June 30, 2014. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2014, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to the Company s management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting that occurred during the three months ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. Other Information

I tem 1. Legal Proceedings

See Part I, Item 1, Note 9 Commitments and Contingencies of this Form 10-Q, which is incorporated in this item by reference.

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Item 1A. Risk Factors

There have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2013 Annual Report and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers for the three months ended June 30, 2014:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
April 1 - April 30	3,720	$ 47.67		
May 1 - May 31	615	46.14		
June 1 - June 30	4,447	46.49		
Total	8,782	$ 46.97		

(1) All of the shares were surrendered by our employees and certain of our directors to pay tax withholding upon the vesting of restricted stock awards. We do not have a publicly announced program to repurchase shares of common stock.

Issuance of Unregistered Securities

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit Number	Description
4.1	Third Supplemental Indenture, dated as of May 29, 2014, among Rosetta Resources Inc., as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K filed on May 29, 2014 (Registration No. 000-51801)).
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

*   Filed herewith

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SIGNATURES

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

ROSETTA RESOURCES INC.

By: /s/ John E. Hagale
John E. Hagale

Executive Vice President and Chief Financial Officer

(Duly Authorized Officer and Principal Financial Officer)

Date: August 4, 2014