Rosetta Resources Inc.
Form 10-Q
May 04, 2015
Table of Contents

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 March 31, 2015

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 April 24, 2015 was 75,696,189, which excludes unvested restricted stock.

Table of Contents

Table of Contents

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	March 31, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 9,127	$ 34,397
Accounts receivable	92,471	117,070
Derivative instruments	210,324	221,250
Prepaid expenses	9,107	8,142
Other current assets	4,249	3,535
Total current assets	325,278	384,394
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	5,518,122	5,337,537
Unproved/unevaluated properties, not subject to amortization	521,842	550,979
Gathering systems and compressor stations	286,867	285,989
Other fixed assets	34,087	34,339
	6,360,918	6,208,844
Accumulated depreciation, depletion and amortization, including impairment	(3,332,570)	(2,434,003)
Total property and equipment, net	3,028,348	3,774,841
Other assets:		
Debt issuance costs	25,731	25,741
Deferred tax asset	85,385	
Derivative instruments	61,645	65,419
Other long-term assets	68	272
Total other assets	172,829	91,432
Total assets	$ 3,526,455	$ 4,250,667
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 179,339	$ 179,353
Royalties and other payables	64,802	98,972

Deferred income taxes	72,565	72,445
Total current liabilities	316,706	350,770
Long-term liabilities:		
Long-term debt	1,840,000	2,000,000
Deferred income taxes		207,854
Other long-term liabilities	27,495	22,930
Total liabilities	2,184,201	2,581,554
Commitments and Contingencies (Note 9)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2015 or 2014		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 74,684,429 shares and 62,306,601 shares at March 31, 2015 and December 31, 2014, respectively	75	62
Additional paid-in capital	1,405,916	1,192,836
Treasury stock, at cost; 801,651 shares and 788,493 shares at March 31, 2015 and December 31, 2014, respectively	(27,702)	(27,414)
Accumulated other comprehensive loss	(224)	(234)
(Accumulated deficit) retained earnings	(35,811)	503,863
Total stockholders equity	1,342,254	1,669,113
Total liabilities and stockholders equity	$ 3,526,455	$ 4,250,667

See accompanying notes to the consolidated financial statements.

Table of Contents

Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended March 31, 2015	2014
Revenues:		
Oil sales	$ 62,517	$ 131,677
NGL sales	25,895	55,295
Natural gas sales	37,229	51,379
Derivative instruments	47,503	(23,785)
Total revenues	173,144	214,566
Operating costs and expenses:		
Lease operating expense	21,822	19,521
Treating and transportation	24,414	20,677
Taxes, other than income	8,679	10,206
Depreciation, depletion and amortization	100,757	74,775
Impairment of oil and gas properties	798,133	
Reserve for commercial disputes	9,200	
General and administrative costs	21,920	19,538
Total operating costs and expenses	984,925	144,717
Operating (loss) income	(811,781)	69,849
Other expense (income):		
Interest expense, net of interest capitalized	22,048	15,290
Interest income	(1)	(12)
Other (income) expense, net	(185)	151
Total other expense	21,862	15,429
(Loss) income before provision for income taxes	(833,643)	54,420
Income tax (benefit) expense	(293,969)	19,177
Net (loss) income	$ (539,674)	$ 35,243
(Loss) earnings per share:		
Basic	$ (8.42)	$ 0.57
Diluted	$ (8.42)	$ 0.57

Weighted average shares outstanding:		
Basic	64,082	61,380
Diluted	64,082	61,547

See accompanying notes to the consolidated financial statements.

Table of Contents

Rosetta Resources Inc.

Consolidated Statement of Comprehensive Income

(In thousands)

(Unaudited)

	Three Months Ended March 31, 2015		2014	
Net (loss) income	$	(539,674)	$	35,243
Other comprehensive income (loss):				
Postretirement medical benefits prior service benefit, net of income taxes of ($5) and ($2), respectively		10		3
Other comprehensive income		10		3
Comprehensive (loss) income	$	(539,664)	$	35,246

See accompanying notes to the consolidated financial statements.

Table of Contents

Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Three Months Ended March 31, 2015	2014
Cash flows from operating activities:		
Net (loss) income	$ (539,674)	$ 35,243
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	100,757	74,775
Impairment of oil and gas properties	798,133	
Deferred income taxes	(293,969)	18,604
Amortization of deferred loan fees recorded as interest expense	1,020	984
Stock-based compensation expense	2,950	3,358
Loss due to change in fair value of derivative instruments	14,700	15,848
Change in operating assets and liabilities:		
Accounts receivable	24,599	(7,625)
Prepaid expenses	(427)	1,956
Other current assets	(714)	(880)
Long-term assets	204	43
Accounts payable and accrued liabilities	34,952	3,264
Royalties and other payables	(34,170)	5,277
Other long-term liabilities	(690)	377
Net cash provided by operating activities	107,671	151,224
Cash flows from investing activities:		
Acquisitions of oil and gas assets		(79,015)
Additions to oil and gas assets	(176,078)	(268,836)
Disposals of oil and gas assets	558	8
Net cash used in investing activities	(175,520)	(347,843)
Cash flows from financing activities:		
Borrowings on Credit Facility	110,000	80,000
Payments on Credit Facility	(270,000)	(20,000)
Proceeds from issuance of common stock	204,415	
Deferred loan fees	(1,548)	
Proceeds from stock options exercised		61
Purchases of treasury stock	(288)	(2,133)
Excess tax benefit from share-based awards		22

Net cash provided by financing activities		42,579		57,950
Net decrease in cash		(25,270)		(138,669)
Cash and cash equivalents, beginning of period		34,397		193,784
Cash and cash equivalents, end of period	$	9,127	$	55,115
Supplemental disclosures:				
Capital expenditures included in Accounts payable and accrued liabilities	$	94,340	$	206,867
Operating liabilities settled in stock	$	6,419	$	

See accompanying notes to the consolidated financial statements.

Table of Contents

Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

(Unaudited)

	Common Stock			Treasury Stock		Accumulated	Retained	
	Shares	Amount	Additional Paid-In Capital	Shares	Amount	Other Comprehensive Loss	Earnings / Accumulated Deficit	Total Stockholders Equity
Balance at December 31, 2014	62,306,601	$ 62	$ 1,192,836	788,493	$ (27,414)	$ (234)	$ 503,863	$ 1,669,113
Issuance of common stock	12,000,000	12	204,403					204,415
Treasury stock - employee tax payment				13,158	(288)			(288)
Tax impact of stock awards			(845)					(845)
Stock-based compensation			3,103					3,103
Vesting of restricted stock	122,247							
Operating liabilities settled in stock	255,581	1	6,419					6,420
Comprehensive income (loss)						10	(539,674)	(539,664)
Balance at March 31, 2015	74,684,429	$ 75	$ 1,405,916	801,651	$ (27,702)	$ (224)	$ (35,811)	$ 1,342,254

See accompanying notes to the consolidated financial statements.

7

Table of Contents

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, 2014 (2014 Annual Report).

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2014 Annual Report. There have been no changes to the Company s significant accounting policies since December 31, 2014.

Recent Accounting Developments

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-01, *Income Statement - Extraordinary and Unusual Items*. The ASU removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed, and the pronouncement is effective for interim and annual reporting periods beginning after December 15, 2015. 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 consists of the following:

	March 31, 2015	December 31, 2014
	(In thousands)	
Proved properties	$ 5,518,122	$ 5,337,537
Unproved/unevaluated properties	521,842	550,979
Gathering systems and compressor stations	286,867	285,989

Other fixed assets	34,087	34,339
Total	6,360,918	6,208,844
Less: Accumulated depreciation, depletion and amortization, including impairment	(3,332,570)	(2,434,003)
Total property and equipment, net	$ 3,028,348	$ 3,774,841

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 $83.8 million.

Table of Contents

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 $1.6 million of internal costs for the three months ended March 31, 2015 and 2014, respectively.

Oil and gas properties include unevaluated property costs of $521.8 million and $551.0 million as of March 31, 2015 and December 31, 2014, 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.

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 March 31, 2015, which were based on a West Texas Intermediate oil price of $79.21 per Bbl and a Henry Hub natural gas price of $3.88 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount was less than the net capitalized cost of oil and natural gas properties as of March 31, 2015, and as a result, a pre-tax write-down of $798.1 million was recorded at March 31, 2015. Additional material write-downs of the Company s oil and gas properties will occur in subsequent quarters in the event that oil and natural gas prices remain at current depressed levels, or if 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, basis 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.

As of March 31, 2015, 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	2015	Costless Collar	7,778	2,139,001	$ 55.00	$ 84.79
Crude oil	2015	Swap	12,000	3,300,000	89.81	
Crude oil	2016	Swap	6,000	2,196,000	90.28	
				7,635,001		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2015	Swap	3,476	955,952	$ 11.31
NGL-Propane	2015	Swap	1,750	481,250	43.35
NGL-Isobutane	2015	Swap	617	169,583	53.05
NGL-Normal Butane	2015	Swap	579	159,107	52.53
NGL-Pentanes Plus	2015	Swap	579	159,107	77.72
				1,924,999	

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	2015	Costless Collar	50,000	13,750,000	$ 3.60	$ 5.04
Natural gas	2016	Costless Collar	40,000	14,640,000	3.50	5.58
Natural gas	2015	Swap	50,000	13,750,000	4.13	
Natural gas	2016	Swap	30,000	10,980,000	4.04	
				53,120,000		

As of March 31, 2015, 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

Table of Contents

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 2014 Annual Report. As of March 31, 2015, the Company had no deposits for collateral regarding commodity derivative positions.

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 March 31, 2015 and December 31, 2014, respectively:

		Asset (Liability) Fair Value	
		March 31, 2015	**December 31, 2014**
Commodity derivative contracts	**Location on Consolidated Balance Sheet**	(In thousands)	
Oil	Derivative instruments - current assets	$ 146,443	$ 151,363
Oil	Derivative instruments - non-current assets	47,863	54,187
NGL	Derivative instruments - current assets	26,889	35,992
Natural gas	Derivative instruments - current assets	36,992	33,895
Natural gas	Derivative instruments - non-current assets	13,782	11,232
Total derivative fair value, net, not designated as hedging instruments		$ 271,969	$ 286,669

The following table sets forth the type and amount of derivative gains and losses included in Derivative instruments in the Consolidated Statement of Operations for the three months ended March 31, 2015 and 2014, respectively:

		Three Months Ended March 31,	
Location on Consolidated Statement of Operations	**Description of Gain (Loss)**	**2015**	**2014**
		(In thousands)	
Derivative instruments	Realized gain (loss) recognized in income	$ 62,203	$ (7,937)
Derivative instruments	Unrealized loss recognized in income	(14,700)	(15,848)
	Total commodity derivative gain (loss) recognized in income	$ 47,503	$ (23,785)

(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.

As defined in the guidance of the 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.

Table of Contents

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 March 31, 2015				
	Level 1	Level 2	Level 3	Netting (1)	Total
			(In thousands)		
Assets:					
Commodity derivative contracts	$	$	$ 272,726	$ (757)	$ 271,969
Liabilities:					
Commodity derivative contracts			(757)	757	
Total fair value	$	$	$ 271,969	$	$ 271,969

	Fair value as of December 31, 2014				
	Level 1	Level 2	Level 3	Netting (1)	Total
			(In thousands)		
Assets:					
Commodity derivative contracts	$	$	$ 289,878	$ (3,209)	$ 286,669
Liabilities:					
Commodity derivative contracts			(3,209)	3,209	
Total fair value	$	$	$ 286,669	$	$ 286,669

(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.

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 March 31, 2015 (in thousands):

Level 3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average

Oil swaps	$ 185,817	Discounted cash flow	Forward price curve-swaps	$ 48.18	$ 62.53	$ 55.99
Oil costless collars	8,489	Option model	Forward price curve-costless collar option value	(0.41)	5.16	3.97
NGL swaps	26,889	Discounted cash flow	Forward price curve-swaps	0.17	1.17	0.43
Natural gas swaps	29,460	Discounted cash flow	Forward price curve-swaps	(0.10)	3.36	2.90
Natural gas costless collars	21,314	Option model	Forward price curve-costless collar option value	(0.07)	1.27	0.75
Total	$ 271,969					

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 a downward adjustment to the fair value of its derivative instruments in the amount of $0.6 million as of March 31, 2015 due to nonperformance risk.

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.

Table of Contents

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

	Derivative Asset (Liability) (In thousands)
Balance at January 1, 2015	$ 286,669
Total Gains (Realized or Unrealized):	
Included in Earnings	47,503
Purchases, Issuances and Settlements:	
Settlements	(62,203)
Transfers in and out of Level 3	
Balance at March 31, 2015	$ 271,969

	Derivative Asset (Liability) (In thousands)
Balance at January 1, 2014	$ 4,419
Total Losses (Realized or Unrealized):	
Included in Earnings	(23,785)
Purchases, Issuances and Settlements:	
Settlements	7,937
Transfers in and out of Level 3	
Balance at March 31, 2014	$ (11,429)

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 March 31, 2015, the carrying value of cash and cash equivalents, 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) and borrowings under the Credit Facility (defined below). The fair values of the Company s Senior Notes are based upon unadjusted quoted market prices and are considered Level 1 instruments. The Company s borrowings under the Credit Facility approximate fair value as the interest rates are variable and reflective of current market rates, and are therefore considered a Level 1 instrument. As of March 31, 2015, the carrying amount of total debt was $1.84 billion and the estimated fair value of total debt was $1.74 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:

	Three Months Ended March 31, 2015 (In thousands)
ARO as of December 31, 2014	$ 19,957
Liabilities incurred during period	62
Liabilities settled during period	(328)
Accretion expense	323
ARO as of March 31, 2015	$ 20,014

As of March 31, 2015, the $0.2 million current portion of the total ARO is included in Accrued liabilities, and the $19.8 million long-term portion of ARO is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Debt and Credit Agreements

Senior Secured Revolving Credit Facility. On February 18, 2015, the Company entered into the Ninth Amendment to the 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, modified the Company s financial covenant requirements by replacing its debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment (EBITDA) leverage ratio with two additional covenants: a senior secured leverage ratio and an interest coverage ratio, both described below.

As of March 31, 2015, the Company had $40.0 million outstanding with $760.0 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 months ended March 31, 2015 was 1.96%, exclusive of commitment fees. For the three months ended March 31, 2015, interest expense was $0.9 million and commitment fees were $0.6 million 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 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 senior secured leverage ratio of secured debt to EBITDA, of not greater than 2.5 to 1.0, and an interest coverage ratio of EBITDA to gross interest, of not less than 2.5 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 March 31, 2015, the Company s current ratio was 2.8, senior secured leverage ratio was 0.1 and interest coverage ratio was 6.0. 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 due 2018, 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.

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 March 31, 2015, the Company had total indebtedness of $1.84 billion, and for the three months ended March 31, 2015, the Company s weighted average borrowing rate was 5.55%, inclusive of interest and commitment fees.

Table of Contents

Subsequent Event. On April 21, 2015, the Company s semi-annual borrowing base redetermination was completed for the Credit Facility and the Company s borrowing base and elected commitment amount were reaffirmed by the Company s lenders at $950.0 million and $800.0 million, respectively.

(8) Income Taxes

The Company s effective tax rate for the three months ended March 31, 2015 and 2014 was 35.3% and 35.2%, respectively. The provision for income taxes 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 March 31, 2015 and December 31, 2014, the Company had no unrecognized tax benefits. The Company does not anticipate that the balance of unrecognized tax benefits will significantly change within the next twelve months due to the settlement of audits or expiration of statutes of limitations.

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 March 31, 2015, the Company had a net deferred tax asset of $12.8 million resulting primarily from differences between the book basis and tax basis of the Company s oil and natural gas properties. The Company believes this deferred tax asset will be fully realized through the generation of future taxable income, and because it is more likely than not to be realized, no valuation allowance has been provided against this deferred tax asset. However, the realizable amount of the deferred tax asset could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

(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, including an aggregate minimum commitment to deliver 4.1 MMBbls of oil by the end of 2017 and 575 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. However, 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 may expose the Company to additional volume deficiency payments. As of March 31, 2015, the Company has accrued deficiency fees of $4.9 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 March 31, 2015 are as follows:

	March 31, 2015 (In thousands)
2015	$ 16,664
2016	22,132
2017	21,708
2018	18,159

2019		15,900
Thereafter		86,507
Total future obligations	$	181,070

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 March 31, 2015, the Company had no outstanding drilling rig commitments with a term greater than one year, and the minimum contractual commitments due in the next twelve months are $7.0 million. For the three months ended March 31, 2015, the Company recorded approximately $15.8 million in rig termination fees. As of March 31, 2015, the Company s minimum contractual commitments due in the next twelve months for other field services were $5.2 million. Payments under these commitments are accounted for as capital additions to oil and gas properties.

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.

Commercial Disputes. For the three months ended March 31, 2015, the Company recorded a reserve of $9.2 million related to a commercial dispute concerning the calculation of royalty amounts earned and royalty deductions taken over specified periods in 2009 through 2013. The dispute arose in the third quarter of 2014 and the Company has been in ongoing discussions with those royalty holders regarding their royalty claim. The Company s total recorded reserve of $15.0 million represents its expected loss exposure associated with this dispute and the final resolution of this matter is expected to occur in the second quarter of 2015. The reserve for this contingency is reported in Reserve for commercial disputes in the Consolidated Statement of Operations and is included in Accounts payable and accrued liabilities in the Consolidated Balance Sheet.

(10) Equity

Earnings per Share. Basic earnings per share (EPS) is calculated by dividing 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 March 31,	
	2015	**2014**
	(In thousands)	
Basic weighted average number of shares outstanding	64,082	61,380
Dilution effect of stock options and restricted shares at the end of the period (1)		167
Diluted weighted average number of shares outstanding	64,082	61,547
Anti-dilutive stock awards and shares	566	9

(1) Because the Company recognized a net loss for the three months ended March 31, 2015, no unvested stock awards and options were included in computing earnings per share because the effect was anti-dilutive.

Common Stock Offering. On March 13, 2015, the Company completed its public offering of 12,000,000 shares of common stock at a price to the public of $17.20 per share ($17.04 per share, net of underwriting discount) for net proceeds of approximately $204.5 million.

Subsequent Event. The Company also received net proceeds of approximately $30.7 million in connection with the underwriters full exercise of their over-allotment option to purchase an additional 1,800,000 shares of common stock, which closed on April 8, 2015.

(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 March 31,	
	2015	**2014**
	(In thousands)	
Total stock-based compensation expense	$ 3,103	$ 3,481
Capitalized in oil and gas properties	(153)	(123)
Net stock-based compensation expense	$ 2,950	$ 3,358

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 months ended March 31, 2015, the Company recorded stock-based compensation expense of approximately $2.9 million related to these equity awards. As of March 31, 2015, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $21.2 million.

Stock-based compensation expense associated with the PSUs granted to management is recognized over a three-year performance period. For the three months ended March 31, 2015, the Company recognized compensation expense of $0.2 million associated with the PSUs. At the current fair value as of March 31, 2015, 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 $13.0 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 2015 annual meeting under the heading Compensation Discussion and Analysis and the Company s 2014 Annual Report.

Postretirement Health Care. The Company has a postretirement medical benefit plan covering eligible employees and their eligible dependents. The Company recognizes periodic postretirement benefits costs as a component of General and administrative costs. For both the three months ended March 31, 2015 and 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.

Table of Contents

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 contin 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, 2014 (the 2014 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;

- 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;

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 months ended March 31, 2015 compared to the three months ended March 31, 2014 and material changes in our financial condition since

December 31, 2014. This discussion should be read in conjunction with our 2014 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 March 31, 2015 include the following:

- production of 65.7 MBoe per day compared to 54.3 MBoe per day for the three months ended March 31, 2014;
- 9 gross (7.4 net) operated wells drilled compared to 47 gross (46.5 net) operated wells drilled for the three months ended March 31, 2014; and
- net loss of $539.7 million, or ($8.42) per diluted share, compared to net income of $35.2 million, or $0.57 per diluted share, for the three months ended March 31, 2014.

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 drilling opportunities that offer predictable, long-term production, attractive returns, reserve growth and a balanced commodity mix. Our Permian Basin assets and bolt-on activity further expand our portfolio of long-lived, oil-rich resource projects that we believe will drive our long-term growth and sustainability. We continually monitor market conditions in our cyclical industry and adjust our investment decisions accordingly. Over the long term, we may consider investments in our core areas in the Eagle Ford shale region and in the Permian Basin that offer a viable inventory of projects, including resource-based exploration projects and acquiring producing properties that are in the early development stages.

Our development operations in the Eagle Ford shale are focused in several areas. In 2015, we have been active in the 26,230-acre Gates Ranch leasehold in Webb County where we drilled our original discovery in 2009. We are also active in the Lasseter and Eppright leases in Central Dimmit County, and in the Tom Hanks lease in northern LaSalle County. Our Briscoe Ranch lease in Dimmit County is held by production, which provides flexibility on timing of our ongoing lower and upper Eagle Ford development activity in that area. As of March 31, 2015, we hold approximately 50,000 acres located in the liquids-producing portions of the play.

Table of Contents

Our delineation operations in the Permian are focused in Reeves County in the Delaware Basin where we are testing benches in the Wolfcamp and 3rd Bone Spring. Currently, we hold 45,500 net acres in the Delaware Basin and approximately 9,300 net exploratory acres in the Midland Basin. We intend to retain our core acreage through minimal capital investments and may divest or allow non-core acreage to expire as part of our long-term strategy in this challenging price environment.

Our assets in the Eagle Ford averaged approximately 58.4 MBoe per day for the three months ended March 31, 2015, a decrease of 10 percent from the fourth quarter of 2014, reflecting our decision to reduce activity levels given the current commodity price environment. Production from the Permian averaged approximately 7.3 MBoe per day in the first quarter of 2015, a decrease of 8 percent from the fourth quarter of 2014. For the three months ended March 31, 2015, our total commodity mix was 28 percent crude oil, 34 percent NGLs and 38 percent natural gas. The Eagle Ford area accounted for approximately 89 percent of our total production for the three months ended March 31, 2015. In addition, crude oil and NGLs represented approximately 58 percent of our production from the Eagle Ford area and 88 percent of our production from the Permian.

We drilled 9 gross operated wells and completed 17 gross operated wells during the quarter ended March 31, 2015. Of these totals, 3 wells were drilled and 14 were completed in the Eagle Ford area. In the Delaware Basin, we drilled 6 gross operated wells and completed 3 gross operated wells, all of which were horizontal. As of March 31, 2015, we had completed a total of 314 gross wells in the Eagle Ford shale since entering the play in 2009. Since initiating our Permian operations in August 2013, we have completed 22 horizontal wells.

In the first quarter of 2015, our total daily equivalent production was 65.7 MBoe per day, an increase of 21 percent from the same period in 2014. For the same period, total daily crude oil production was 18.3 MBbls per day, an increase of 14 percent from the same period in 2014. We have multiple options for transportation and processing capacity with firm commitments and other arrangements in place to meet total planned production levels through 2017.

The first quarter of 2015 was impacted by an uncertain commodity price environment. Reflective of our plans to maintain financial discipline and operate within cash flow, our 2015 capital program contemplates expenditures of approximately $350 million. Approximately 47 percent of our 2015 capital program will be spent on higher return development activities in the Eagle Ford shale in South Texas, including central facilities. In addition, approximately 41 percent of the 2015 capital program will be spent on activities to hold and delineate our leases in the Delaware Basin in West Texas. We expect to allocate the remaining 12 percent for other capital items, including capitalized interest and corporate capital.

While our unconventional resource strategy has proven to be successful, we recognize 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 a diversified production base which includes a balanced mix of crude oil, NGLs and natural gas. Because our production is highly concentrated geographically, we have taken various steps to provide access to necessary services and infrastructure. We believe our 2015 capital program can be executed from internally generated cash flows, borrowings under our Credit Facility, access to capital markets and cash on hand. Effective April 21, 2015, the borrowing base and elected commitment amount under our Credit Facility were reaffirmed by our lenders at $950 million and $800 million, respectively. We used the net proceeds from an equity offering in March 2015 to repay $200.0 million of indebtedness outstanding under our Credit Facility and, as of May 1, 2015, we had no borrowings outstanding and $800 million of borrowing availability. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs.

Results of Operations

Revenues

Our consolidated financial statements for the three months ended March 31, 2015 reflect total revenues of $173.1 million (including derivative gains of $47.5 million) based on total volumes of 65.7 MBoe per day.

Table of Contents

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 March 31, 2015	2014	% Change Increase/ (Decrease)
Revenues (in thousands):			
Oil sales	$ 62,517	$ 131,677	(53%)
NGL sales	25,895	55,295	(53%)
Natural gas sales	37,229	51,379	(28%)
Derivative instruments	47,503	(23,785)	300%
Total revenues	$ 173,144	$ 214,566	(19%)
Production:			
Oil (MBbls)	1,649	1,453	13%
NGLs (MBbls)	2,005	1,670	20%
Natural gas (MMcf)	13,578	10,582	28%
Total equivalents (MBoe)	5,917	4,886	21%
Daily Production:			
Oil (MBbls per day)	18.3	16.1	14%
NGLs (MBbls per day)	22.3	18.6	20%
Natural gas (MMcf per day)	150.9	117.6	28%
Total equivalents (MBoe per day)	65.7	54.3	21%
Average sales price:			
Oil, excluding derivatives (per Bbl)	$ 37.91	$ 90.62	(58%)
Oil, including realized derivatives (per Bbl)	64.89	88.59	(27%)
NGL, excluding derivatives (per Bbl)	12.92	33.11	(61%)
NGL, including realized derivatives (per Bbl)	17.23	31.38	(45%)
Natural gas, excluding derivatives (per Mcf)	2.74	4.86	(44%)
Natural gas, including realized derivatives (per Mcf)	3.41	4.66	(27%)
Revenue, excluding derivatives (per Boe)	21.23	48.78	(56%)
Revenue, including realized derivatives (per Boe)	31.75	47.16	(33%)

Oil sales**.** For the three months ended March 31, 2015, oil sales, excluding the effect of derivative instruments, decreased by $69.2 million from the same period in 2014. The lower average sales price for oil resulted in an $86.9 million decrease in oil sales, partially offset by a $17.7 million increase due to the 2.2 MBbls per day increase in oil production. The increase in oil production was primarily attributable to a 2.5 MBbls per day increase resulting from our growth and development in the Permian Basin, partially offset by a 0.3 MBbls per day decline from the Eagle Ford.

For the three months ended March 31, 2015 and 2014, realized oil derivative gains of $44.5 million and losses of $3.0 million, respectively, are reported as a component of Derivative instruments within Revenues.

NGL sales. For the three months ended March 31, 2015, NGL sales, excluding the effect of derivative instruments, decreased by $29.4 million from the same period in 2014. The lower average sales price for NGLs resulted in a $40.5 million decrease in NGL sales, partially offset by an $11.1 million increase due to the 3.7 MBbls per day increase in NGL production. The increase in NGL production was primarily attributable to an increase of 3.4 MBbls per day at Gates Ranch as a result of our development activities in that area.

For the three months ended March 31, 2015 and 2014, realized NGL derivative gains of $8.7 million and losses of $2.9 million, respectively, are reported as a component of Derivative instruments within Revenues.

Natural gas sales. For the three months ended March 31, 2015, natural gas sales, excluding the effect of derivative instruments, decreased by $14.2 million from the same period in 2014. The lower average sales price for natural gas resulted in a $28.7 million decrease in natural gas sales, partially offset by a $14.5 million increase due to the 33.3 MMcf per day increase in natural gas production. The increase in natural gas production was primarily attributable to an increase of 24.6 MMcf per day at Gates Ranch due to development activities in that area, as well as a 6.6 MMcf per day increase in production in the Encinal area.

For the three months ended March 31, 2015 and 2014, realized natural gas derivative gains of $9.1 million and losses of $2.1 million, respectively, are reported as a component of Derivative instruments within Revenues.

Derivative instruments. For the three months ended March 31, 2015, Derivative instruments included (i) a realized derivative gain of $62.2 million from cash settlements associated with our commodity derivative contracts, and (ii) an unrealized derivative loss of $14.7 million due to changes in the fair value of our commodity derivative contracts.

For the three months ended March 31, 2014, Derivative instruments included (i) a realized derivative loss of $7.9 million from cash settlements associated with our commodity derivative contracts, and (ii) an unrealized derivative loss of $15.8 million due to changes in the fair value of our commodity derivative contracts.

Operating Expenses

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

	Three Months Ended March 31,		
	2015	**2014**	**% Change Increase/ (Decrease)**
	(In thousands, except percentages and per unit amounts)		
Direct lease operating expense	$ 16,533	$ 15,786	5%
Insurance expense	296	269	10%
Workover expense	4,993	3,466	44%
Lease operating expense (Production costs)	$ 21,822	$ 19,521	12%
Treating and transportation	24,414	20,677	18%
Taxes, other than income	8,679	10,206	(15%)
Depreciation, depletion and amortization (DD&A)	100,757	74,775	35%
Impairment of oil and gas properties	798,133		100%
Reserve for commercial disputes	9,200		100%
General and administrative costs	21,920	19,538	12%
Costs and expenses (per Boe of production)			
Lease operating expense (Production costs)	$ 3.69	$ 4.00	(8%)
Treating and transportation	4.13	4.23	(2%)
Taxes, other than income	1.47	2.09	(30%)
Depreciation, depletion and amortization (DD&A)	17.03	15.30	11%
General and administrative costs	3.70	4.00	(7%)
General and administrative costs, excluding stock-based compensation	3.21	3.31	(3%)

Lease operating expense. Lease operating expense increased as result of year-over-year production growth as well as increased workover activity in the Eagle Ford area, which contributed $1.2 million of the increase for the three months ended March 31, 2015.

Treating and transportation. Treating and transportation expense increased as a result of increased daily production in both core areas for the three months ended March 31, 2015, partially offset by lower per unit expense due to the utilization of lower-cost transportation and processing primarily in the Eagle Ford area. Additionally, during the three months ended March 31, 2015, we have accrued deficiency fees of $3.9 million related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements.

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, decreased as a result of a $0.62 per Boe decrease in unit costs, which represented $3.7 million of the decrease, partially offset by a $2.2 million increase in Taxes, other than income, due to the 11.4 MBoe per day increase in production.

Depreciation, depletion and amortization. For the three months ended March 31, 2015, DD&A expense increased from the same period in 2014 as a result of increased depletion rates due to the inclusion of higher-cost Permian reserves in our depletion pool, as well as the 21% increase in equivalent daily production. With the inclusion of the impairment in our depletion pool, we anticipate a decrease in our DD&A rate starting in the second quarter of 2015.

Table of Contents

Impairment of oil and gas properties. Pursuant to full cost accounting rules, we must perform a ceiling test each quarter on our proved oil and natural gas assets. Our ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of March 31, 2015, which were based on a West Texas Intermediate oil price of $79.21 per Bbl and a Henry Hub natural gas price of $3.88 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount was less than the net capitalized cost of oil and natural gas properties as of March 31, 2015, and as a result, a pre-tax write-down of $798.1 million was recorded at March 31, 2015. Additional material write-downs of our oil and gas properties will occur in subsequent quarters in the event that oil and natural gas prices remain at current depressed levels, or if we experience significant downward adjustments to our estimated proved reserves.

Reserve for commercial disputes. We recorded a reserve of $9.2 million during the three months ended March 31, 2015 related to a commercial dispute that arose during the third quarter of 2014. Our total recorded reserve of $15.0 million as of March 31, 2015 represents our expected loss exposure associated with this dispute and the final resolution of this matter is expected to occur in the second quarter of 2015. The reserve for this contingency is reported in Reserve for commercial disputes in the Consolidated Statement of Operations and is included in Accounts payable and accrued liabilities in the Consolidated Balance Sheet.

General and administrative costs. For the three months ended March 31, 2015, General and administrative costs increased from the same period in 2014 as a result of a $3.3 million increase in personnel costs attributable to increased headcount, partially offset by a $0.4 million decrease in stock-based compensation expense driven by our performance share units and a $0.5 million decrease in other administrative costs.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense, increased $6.4 million for the three months ended March 31, 2015 compared to the same period in 2014. The increase was a result of higher interest expense due to the issuance of our 5.875% Senior Notes due 2024 in May 2014 in addition to lower capitalized interest. The weighted average interest rate, inclusive of interest and commitment fees, for the three months ended March 31, 2015 was 5.55% compared to 6.26% for the same period in 2014. The decrease in the weighted average interest rate was due to the redemption of the 9.500% Senior Notes in the second quarter of 2014.

Provision for Income Taxes

The effective tax rate for the three months ended March 31, 2015 and 2014 was 35.3% and 35.2%, 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 March 31, 2015 and December 31, 2014, we had no unrecognized tax benefits, and we do not anticipate that the balance of unrecognized tax benefits will significantly change within the next twelve months due to the settlement of audits or expiration of statutes of limitations.

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 March 31, 2015, we had a net deferred tax asset of $12.8 million resulting primarily from differences between the book basis and tax basis of our oil and natural gas properties. We believe this deferred tax asset will be fully realized through the generation of future taxable income, and because it is more likely than not to be realized, no valuation allowance has been provided against our deferred tax asset. However, the realizable amount of the deferred tax asset could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

Liquidity and Capital Resources

Our sources of liquidity and capital are our operating cash flow, borrowings under our Credit Facility and our cash on hand.

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 our exposure to commodity price risk, 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.

Table of Contents

Cash Flows

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

	Three Months Ended March 31, 2015	2014
	(In thousands)	
Cash provided by (used in):		
Operating activities	$ 107,671	$ 151,224
Investing activities	(175,520)	(347,843)
Financing activities	42,579	57,950
Net decrease in cash and cash equivalents	$ (25,270)	$ (138,669)

Operating Activities. The decrease in net cash provided by operating activities for the three months ended March 31, 2015 compared to the same period in 2014 reflects lower realized commodity prices.

Investing Activities. The reduction in net cash used in investing activities for the three months ended March 31, 2015 compared to the same period in 2014 reflects a reduction in our capital spending and acquisition activity.

Financing Activities. The reduction in net cash provided by financing activities for the three months ended March 31, 2015 compared to the same period in 2014 reflects net repayments of $160.0 million under the Credit Facility and $1.5 million in deferred loan fees, partially offset by $204.4 million in proceeds from the issuance of common stock.

Capital Expenditures and Requirements

Our historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2014 Annual Report and is incorporated herein by reference.

Our accrual-basis capital expenditures for the three months ended March 31, 2015 decreased by $292.9 million to $151.5 million from $444.4 million for the three months ended March 31, 2014. During the three months ended March 31, 2015, we drilled 9 and completed 17 gross operated wells. Of these totals, 3 wells were drilled and 14 were completed in the Eagle Ford area. In the Delaware Basin, we drilled 6 gross operated wells and completed 3 gross operated wells, all of which were horizontal. Our capital budget for 2015 is projected to be $350 million.

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 may be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management has hedged oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps and costless collars. 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. The notional volumes hedged equate to a substantial portion of our 2015 projected equivalent production and a portion of our 2016 projected equivalent production. 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 March 31, 2015, a description of the applicable accounting and the estimated fair market values as of March 31, 2015. 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 2014 Annual Report.

Table of Contents

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 2014 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, NGL 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 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 March 31, 2015, we have accrued deficiency fees of $4.9 million. As of March 31, 2015, 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.

As noted in Note 9 Commitments and Contingencies included in Part I. Item 1. Financial Statements of this Form 10-Q, we recorded a reserve of $9.2 million related to a commercial dispute. Our total recorded reserve of $15.0 million as of March 31, 2015 represents our expected loss exposure associated with this dispute and the final resolution of this matter is expected to occur in the second quarter of 2015.

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 2014 Annual Report and Note 4 Commodity Derivative Contracts included in Part I. Item 1. Financial Statements of this Form 10-Q.

As of March 31, 2015, we had open crude oil derivative contracts in a net asset position with a fair value of $194.3 million. A 10% increase in crude oil prices would reduce the fair value by approximately $34.0 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $35.8 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.

Table of Contents

As of March 31, 2015, we had open NGL derivative contracts in a net asset position with a fair value of $26.9 million. A 10% increase in NGL prices would reduce the fair value by approximately $3.4 million, while a 10% decrease in NGL prices would increase the fair value by approximately $3.4 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 March 31, 2015, we had open natural gas derivative contracts in a net asset position with a fair value of $50.8 million. A 10% increase in natural gas prices would reduce the fair value by approximately $13.0 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $13.7 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 March 31, 2015, 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 March 31, 2015, 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 March 31, 2015. 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 a downward adjustment to the fair value of our derivative instruments in the amount of $0.6 million as of March 31, 2015. 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 have entered into oil, NGL and natural gas derivative contracts through 2016 which hedge our exposure to commodity price risk. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices exceed the prices established by the contracts. As of March 31, 2015, 41% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 59% at Light Louisiana Sweet; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 84% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, with the remaining 16% at Tennessee, zone 0.

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 March 31, 2015. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of March 31, 2015, 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 our 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 March 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II. Other Information

Item 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.

Item 1A. Risk Factors

There have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2014 Annual Report.

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 March 31, 2015:

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
January 1 - January 31	11,310	$	22.24		
February 1 - February 28	1,848		19.61		
March 1 - March 31					
Total	13,158	$	21.87		

(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.

Securities Authorized for Issuance under Equity Compensation Plans

See the definitive proxy statement filed with respect to the Company s 2015 annual meeting under the heading Securities Authorized for Issuance Under Equity Compensation Plans and the Company s 2014 Annual Report for information regarding shares of common stock authorized for issuance under our long-term incentive plans.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description
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

Table of Contents

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: May 4, 2015