MICRON SOLUTIONS INC /DE/
Form 10-Q
August 14, 2018
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 Q

Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2018 or

Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ______ to ______

001-9731

(Commission file No.)

Micron Solutions, Inc.

(Exact name of registrant as specified in its charter)

DELAWARE	72 0925679
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)

25 Sawyer Passway

Fitchburg, Massachusetts 01420

(Address of principal executive offices and zip code)

(978) 345-5000

(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed from last report)

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 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer”, “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer Accelerated filer Non Accelerated filer Smaller reporting company

Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of August 13, 2018 there were 2,850,177 shares of the Company’s common stock outstanding.

Table of Contents

Micron Solutions, Inc. and Subsidiary

TABLE OF CONTENTS

PART I - CONDENSED FINANCIAL STATEMENTS		3
Item 1	Condensed Consolidated Financial Statements	3
	Condensed Consolidated Balance Sheets	3
	Condensed Consolidated Statements of Operations	4
	Condensed Consolidated Statements of Cash Flows	5
	Notes to the Condensed Consolidated Financial Statements	6
Item 2	Management’s Discussion and Analysis of Financial Condition and Results of Operations	15
Item 3	Quantitative and Qualitative Disclosures about Market Risk	21
Item 4	Controls and Procedures	21
PART II - OTHER INFORMATION		23
Item 6	Exhibit Index	23
	SIGNATURES	25

PART I - CONDENSED FINANCIAL STATEMENTS

Item 1. Condensed Consolidated Financial Statements (unaudited)

Micron Solutions, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

(unaudited)

	June 30, 2018	December 31, 2017

Assets		
Current assets:		
Cash and cash equivalents	$ —	$ 606,988
Restricted cash	—	350,000
Trade accounts receivable, net of allowance for doubtful accounts of $40,000 at June 30, 2018 and December 31, 2017, respectively	3,052,691	2,595,248
Inventories	3,645,152	3,413,199
Prepaid expenses and other current assets	246,474	460,954
Total current assets	6,944,317	7,426,389
Property, plant and equipment, net	5,236,305	5,744,039
Assets held for sale, net	688,750	688,750
Intangible assets, net	53,224	55,133
Other assets	4,135	10,289
Total assets	$ 12,926,731	$ 13,924,600
Liabilities and Shareholders' Equity		
Current liabilities:		
Revolving line of credit	$ 1,307,954	$ 1,879,047
Term notes payable, current portion	390,709	367,779
Subordinated promissory notes, current portion	—	350,000
Accounts payable	1,326,070	1,534,349
Accrued expenses and other current liabilities	426,793	320,065
Contract liabilities, current portion	736,570	426,457
Total current liabilities	4,188,096	4,877,697
Long-term liabilities:		
Term notes payable, non-current portion	3,767,167	3,978,415
Total long-term liabilities	3,767,167	3,978,415
Total liabilities	7,955,263	8,856,112
Commitments and Contingencies		
Shareholders' equity:		
Preferred stock, $0.001 par value; 2,000,000 shares authorized, none issued	—	—
Common stock, $0.01 par value; 10,000,000 shares authorized; 3,926,491 issued, 2,850,177 outstanding at June 30, 2018 and 3,926,491 issued, 2,839,274 outstanding at December 31, 2017	39,265	39,265
Additional paid-in-capital	11,565,392	11,532,207
Treasury stock at cost, 1,076,314 shares at June 30, 2018 and 1,087,217 shares at December 31, 2017	(2,937,046)	(2,966,798)
Accumulated deficit	(3,696,143)	(3,536,186)
Total shareholders' equity	4,971,468	5,068,488
Total liabilities and shareholders' equity	$ 12,926,731	$ 13,924,600

See accompanying notes to condensed consolidated financial statements.

Table of Contents

Micron Solutions, Inc. and Subsidiary

Condensed Consolidated Statements of Operations

(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net sales	$ 5,320,426	$ 5,390,726	$ 10,439,474	$ 10,655,703
Cost of sales	4,442,606	5,008,889	8,830,294	9,620,492
Gross profit	877,820	381,837	1,609,180	1,035,211
Selling and marketing	204,036	234,820	394,576	500,693
General and administrative	529,092	552,678	1,133,127	1,169,508
Research and development	26,801	28,344	54,722	57,640
Total operating expenses	759,929	815,842	1,582,425	1,727,841
Net income (loss) from operations	117,891	(434,005)	26,755	(692,630)
Other income (expense):				
Interest expense	(96,016)	(87,429)	(193,028)	(151,330)
Other income, net	11,806	9,981	20,307	34,070
Total other expense, net	(84,210)	(77,448)	(172,721)	(117,260)
Net income (loss) before income tax provision (benefit)	33,681	(511,453)	(145,966)	(809,890)
Income tax provision (benefit)	—	—	—	—
Net income (loss)	$ 33,681	$ (511,453)	$ (145,966)	$ (809,890)
Comprehensive income (loss)	33,681	(511,453)	$ (145,966)	$ (809,890)
Earnings (loss) per share - basic	$ 0.01	$ (0.18)	$ (0.05)	$ (0.29)
Earnings (loss) per share - diluted	$ 0.01	$ (0.18)	$ (0.05)	$ (0.29)
Weighted average common shares outstanding - basic	2,847,642	2,820,999	2,844,889	2,819,915
Weighted average common shares outstanding - diluted	2,855,101	2,820,999	2,844,889	2,819,915

See accompanying notes to condensed consolidated financial statements.

Table of Contents

Micron Solutions, Inc. and Subsidiary

Condensed Consolidated Statements of Cash Flows

(unaudited)

	Six Months Ended June 30, 2018	2017
Cash flows from operating activities:		
Net loss	$ (145,966)	$ (809,890)
Adjustments to reconcile net loss to net cash provided by (used in)		
operating activities:		
Gain on sale of property, plant and equipment	—	(21,554)
Depreciation and amortization	767,605	803,217

	$	(6,238)		$			
NGL							
Quantity settled (Bbl)		182,000				245,000	
Decrease in NGL sales revenue (In thousands)	$	(3,039)	$		$	(4,225)	$
Interest Rate Swaps							
(Increase) in interest expense (In thousands)	$		$	(238)	$		$ (490)

(1) For the three months ended June 30, 2011, excludes approximately $8.2 million of realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested Sacramento Basin properties.

(2) For the six months ended June 30, 2011, excludes approximately $2.9 million and $8.2 million, respectively, of realized gains associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties.

(3) For the three and six months ended June 30, 2011, includes approximately $4.8 million of unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

As of June 30, 2011, the Company expects to reclassify net gains of $0.3 million from Accumulated other comprehensive income on the Consolidated Balance Sheet to earnings based upon settlement dates in the next twelve months and based upon current forward prices as of June 30, 2011.

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the statement of financial position. In accordance with this guidance, the Company designates certain commodity forward contracts as cash flow hedges of forecasted sales of natural gas, oil and NGL production and interest rate swaps as cash flow hedges of interest rate payments due under variable-rate borrowings.

Table of Contents

Additional Disclosures about Derivative Instruments and Hedging Activities

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

Non-Qualifying Hedges

Crude oil basis and NYMEX roll swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under Derivative instruments, as assets and/or liabilities, as applicable, and are marked-to-market each period with the change in fair value representing unrealized gains and losses recognized immediately in the unaudited Consolidated Statement of Operations as a component of Oil sales. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying financial instrument contract settlement is made.

As of June 30, 2011, the Company had outstanding natural gas, oil and NGL commodity forward contracts with notional volumes of 16,520,000 MMBtus, 6,418,100 Bbls and 1,081,700 Bbls, respectively, that were entered into to hedge forecasted natural gas, oil and NGL sales.

Information on the location and amounts of derivative fair values in the Consolidated Balance Sheet as of June 30, 2011 and December 31, 2010 and derivative gains and losses in the Consolidated Statement of Operations for the three and six months ended June 30, 2011 and 2010, respectively, is as follows:

Fair Values of Derivative Instruments
Derivative Assets (Liabilities)

	Balance Sheet Location	**Fair Value**	
		June 30, 2011	**December 31, 2010**
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity contracts - natural gas	Derivative instruments - current assets	$ 14,337	$ 24,959
Commodity contracts - natural gas	Derivative instruments - non-current assets		3,614
Commodity contracts - crude oil	Derivative instruments - current assets	(3,304)	(2,696)
Commodity contracts - crude oil	Derivative instruments - non-current assets		(2,207)
Commodity contracts - NGL	Derivative instruments - current assets	(9,515)	(3,118)
Commodity contracts - NGL	Derivative instruments - non-current assets		116
Commodity contracts - natural gas	Derivative instruments - current liabilities		
Commodity contracts - natural gas	Derivative instruments - long-term liabilities	2,081	
Commodity contracts - crude oil	Derivative instruments - current liabilities	(398)	
Commodity contracts - crude oil	Derivative instruments - long-term liabilities	(5,351)	
Commodity contracts - NGL	Derivative instruments - current liabilities	(223)	
Commodity contracts - NGL	Derivative instruments - long-term liabilities	(3,455)	(1,011)
Total derivatives designated as hedging instruments		$ (5,828)	$ 19,657
Derivatives not designated as hedging instruments			
Commodity contracts - crude oil	Derivative instruments - current assets	$ (626)	$
Commodity contracts - crude oil	Derivative instruments - long-term liabilities	(4,158)	
Total derivatives not designated as hedging instruments		$ (4,784)	$

Total derivatives	$ (10,612)	$ 19,657

Table of Contents

Derivatives in Cash Flow Hedging Relationships	Amount Recognized in OCI on Derivative (Effective Portion) Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)			
Commodity contracts - natural gas	$ 1,422	$ 1,047	$ 2,078	$ 33,560
Commodity contracts - crude oil	2,833		(15,172)	
Commodity contracts - NGL	(1,032)		(13,405)	
Interest rate swap		15		(248)
Total	$ 3,223	$ 1,062	$ (26,499)	$ 33,312

Location of Gain or (Loss)	Amount Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)			
Natural gas sales	$ 3,133	$ 5,721	$ 10,404	$ 8,598
Crude oil sales	(5,917)		(6,238)	
NGL sales	(3,039)		(4,225)	
Interest expense, net of interest capitalized		(238)		(490)
Total	$ (5,823)	$ 5,483	$ (59)	$ 8,108

Location of Gain or (Loss)	Amount Recognized in Income on Derivatives (Derivatives Not Designated as Cash Flow Hedges, Ineffective Portion of Cash Flow Hedges and Amount Excluded from Effectiveness Testing) Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)			
Natural gas sales (1) (2)	$ 8,151	$	$ 11,018	$
Crude oil sales (3)	(4,784)		(4,784)	
NGL sales				
Total	$ 3,367	$	$ 6,234	$

(1) For the three months ended June 30, 2011, this amount represents the realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested Sacramento Basin properties.

(2) For the six months ended June 30, 2011, this amount represents the realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties.

(3) For the three and six months ended June 30, 2011, includes approximately $4.8 million of unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

(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. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company s non-financial assets and liabilities were impaired during the period ended June 30, 2011, and the Company had no other material assets or liabilities that are reported at fair value on a non-recurring basis, no additional disclosures are provided as of June 30, 2011.

As defined in the guidance, 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 or 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 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.

Table of Contents

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.

Level 3 instruments include money market funds, natural gas and NGL fixed price swaps, crude oil basis and NYMEX roll swaps and natural gas and crude oil zero cost collars. The Company s money market funds represent cash equivalents whose investments are limited to United States Government securities, securities backed by the United States Government, or securities of United States Government agencies. The fair value represents cash held by the fund manager as of June 30, 2011 and December 31, 2010. The Company identified the money market funds as Level 3 instruments due to the fact that quoted prices for the underlying investments cannot be obtained and there is not an active market for the underlying investments. The Company utilizes, as one of its inputs, counterparty and third party broker quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant New York Mercantile Exchange (NYMEX) futures contracts and exchange traded contracts for each derivative settlement location.

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 as of June 30, 2011. 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 and their placement within the fair value hierarchy levels.

	Fair value as of June 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			(10,612)	(10,612)
Total	$	$	$ (9,577)	$ (9,577)

	Fair value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			19,657	19,657
Total	$	$	$ 20,692	$ 20,692

The determination of the fair values above incorporates various factors. These factors include the credit standing of the counterparty involved, the impact of credit enhancements and the impact of the Company s nonperformance risk on its liabilities. The Company considered credit adjustments for the counterparties using the current credit default swap values and default probabilities for the Company and counterparties in determining fair value and recorded a downward adjustment to the fair value of its derivative liabilities in the amount of $0.2 million at June 30, 2011.

The tables below present reconciliations of the assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods. Level 3 instruments presented in the table consist of net derivatives and money market funds that, in management s judgment, reflect the assumptions a marketplace participant would have used at June 30, 2011 and 2010.

Table of Contents

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2011	$ 19,657	$ 1,035	$ 20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)	(10,959)		(10,959)
Included in Other Comprehensive Income	(26,499)		(26,499)
Purchases, Issuances and Settlements			
Settlements	(3,829)		(3,829)
Purchases	11,018		11,018
Transfers in and out of Level 3			
Balance at June 30, 2011	$ (10,612)	$ 1,035	$ (9,577)

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2010	$ 6,787	$ 2,035	$ 8,822
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)			
Included in Other Comprehensive Income	33,312		33,312
Purchases, Issuances and Settlements	(8,108)		(8,108)
Transfers in and out of Level 3			
Balance at June 30, 2010	$ 31,991	$ 2,035	$ 34,026

(1) No gains or losses were included in earnings attributable to the change in unrealized gains or losses relating to financial assets and liabilities still held at the end of the period.

As of June 30, 2011, the carrying value of cash and cash equivalents, accounts receivable, other current assets and current liabilities reported in the consolidated balance sheet approximate fair value because of their short-term nature. The carrying amount of long-term debt reported in the consolidated balance sheet as of June 30, 2011 is $250.0 million. The Company calculated the fair value of its long-term debt as of June 30, 2011, in accordance with the authoritative guidance for fair value measurements using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality, and risk profile. Based on this calculation, the Company has determined the fair market value of its debt to be $275.7 million at June 30, 2011.

Table of Contents

(6) Asset Retirement Obligations

The following table provides a roll forward of the asset retirement obligations. Liabilities incurred during the period include additions to obligations. Liabilities settled during the period include settlement payments primarily related to offshore obligations of approximately $8.2 million and adjustments for obligations that were assumed by the purchasers of divested properties of approximately $10.5 million. Activity related to the Company s asset retirement obligations (ARO) is as follows:

	Six Months Ended June 30, 2011 (In thousands)
ARO as of December 31, 2010	$ 27,934
Revision of previous estimates	
Liabilities incurred during period	13
Liabilities settled during period	(19,306)
Accretion expense	842
ARO as of June 30, 2011	$ 9,483

As of June 30, 2011, the current portion of the total ARO is approximately $0.1 million and is included in Accrued liabilities and the long-term portion of ARO is approximately $9.4 million and is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Long-Term Debt

Senior Secured Revolving Credit Facility. On May 10, 2011, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, the Company s senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company s hedging arrangements as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including the Company s level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base. The borrowing base under the Restated Revolver is currently set at $325.0 million with the next semi-annual review scheduled to be completed in October 2011.

The Company utilized a portion of the proceeds from its asset divestitures to repay $100.0 million of outstanding debt under the Restated Revolver on April 21, 2011. As of June 30, 2011, the Company had $30.0 million outstanding with $295.0 million of available borrowing capacity under its Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. Borrowings under the Restated Revolver are collateralized by perfected first priority 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 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 subject to the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of 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. At June 30, 2011, the Company s current ratio was 3.8 and the leverage ratio was 0.9. 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. The Company was in compliance with all covenants at June 30, 2011.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of June 30, 2011, the Company had $20.0 million of fixed rate borrowings outstanding bearing interest

14

Table of Contents

at 13.75% under the Restated Term Loan. The Company has the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of the Company s assets. The Company is subject to the financial covenants as defined in the term loan agreement. The Company is required under the term loan agreement to maintain a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require the Company to maintain 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. At June 30, 2011, the Company s reserve coverage ratio was 4.8 and the leverage ratio was 0.9. In addition, the Company is subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at June 30, 2011.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the Senior Notes) in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the 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 Indenture also contains customary events of default. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under the Restated Revolver and $80.0 million of variable rate borrowings outstanding under the Restated Term Loan and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

As of June 30, 2011, the Company had total outstanding borrowings of $250.0 million and for the six months ended June 30, 2011, the Company s weighted average borrowing rate was 8.04%.

(8) Income Taxes

The effective tax rate for the three and six months ended June 30, 2011 was 35.9% and 34.2%, respectively, and the effective tax rate for the three and six months ended June 30, 2010 was 40.8% and 38.5%, respectively. The provision for income taxes for the three months ended June 30, 2011 differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and due the impact of state income taxes. For the six months ended June 30, 2011, the provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and an approximate $0.9 million adjustment for 2010 federal income taxes. The Company has determined that the impact of the 2010 tax adjustment was immaterial to its results of operations in all applicable prior interim and annual periods as well as to the projected results of operations for 2011. As of June 30, 2011 and December 31, 2010, 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 statute of limitations 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, 2011, the Company has a deferred tax asset of $128.8 million resulting primarily from the difference between the book basis and tax basis of oil and natural gas properties and net operating loss carryforwards. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards.

In connection with the asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded that it is more likely than not that the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances were established at December 31, 2010 for these items as well as state NOLs in other jurisdictions in which the Company previously operated but has since divested of operating assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Table of Contents

(9) Commitments and Contingencies

Firm Gas Transportation Commitments. The Company has entered into long-term contracts for firm transportation and processing capacity to reduce exposure to production constraints in the Eagle Ford shale. During the second quarter of 2011, the Company increased its daily transportation capacity from the Eagle Ford shale by 20 percent to 245 MMcf/d of gross wellhead production with 195 MMcf/d contracted to be available by the second quarter of 2012 and total contractual capacity reached by 2013.

Drilling Rig and Completion Services Commitments. As the Company s operations are concentrated in highly competitive plays, access to drilling rigs and other oilfield services can be aggressive, unavailable or costly. Should access to these services be restricted due to market conditions, the Company could be adversely affected. As of June 30, 2011, the Company has no outstanding drilling commitments with terms greater than one year.

In an effort to secure key oil field services, the Company entered into a two-year bundled service agreement effective January 1, 2011 with a major oil field services firm. The agreement includes stimulation, cementing and drilling fluids product service lines sufficient to support the current operations. As of June 30, 2011, the minimum remaining contractual commitment for this agreement was $5.4 million. This minimum commitment will decrease equally on a monthly basis for the remainder of the contract term.

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

(10) Comprehensive Income (Loss)

For the periods indicated, the Company s Accumulated other comprehensive income consisted of the following:

	Three Months Ended June 30,				**Six Months Ended June 30,**			
	2011		**2010**		**2011**		**2010**	
				(In thousands)				
Accumulated other comprehensive (loss) income, beginning of period		$ (12,725)		$ 22,848		$ 11,259		$ 4,259
Net income	$ 25,400		$ 4,312		$ 36,397		$ 11,575	
Change in fair value of derivative hedging instruments	$ 3,223		$ 1,062		$ (26,499)		$ 33,312	
Hedge settlements reclassed to (income) loss	2,456		(5,483)		(6,175)		(8,108)	
Tax provision related to hedges	(1,705)		1,696		12,664		(9,340)	
Total other comprehensive income (loss)	$ 3,974	$ 3,974	$ (2,725)	$ (2,725)	$ (20,010)	$ (20,010)	$ 15,864	$ 15,864
Comprehensive income	$ 29,374		$ 1,587		$ 16,387		$ 27,439	
Accumulated other comprehensive (loss) income, end of period		$ (8,751)		$ 20,123		$ (8,751)		$ 20,123

(11) Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if outstanding common stock awards and stock options were exercised at the end of the period.

16

Table of Contents

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In thousands)			
Basic weighted average number of shares outstanding	51,991	51,355	51,923	51,287
Dilution effect of stock option and awards at the end of the period	590	701	644	726
Diluted weighted average number of shares outstanding	52,581	52,056	52,567	52,013
Anti-dilutive stock awards and shares	1	45	2	64

(12) Stock-Based Compensation Expense

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(in thousands)			
Total stock-based compensation expense	$ 5,743	$ 1,996	$ 16,474	$ 4,626
Capitalized in oil and gas properties	(201)	(141)	(342)	(283)
Net stock-based compensation expense	$ 5,542	$ 1,855	$ 16,132	$ 4,343

All stock-based compensation expense associated with stock-based equity awards granted to employees and directors is recognized on a straight-line basis over the applicable remaining vesting period. For the six months ended June 30, 2011, the Company recorded compensation expense of approximately $2.7 million related to these equity awards. As of June 30, 2011, unrecognized stock-based compensation expense related to unvested stock-based compensation equity awards was approximately $7.4 million.

Stock-based compensation expense associated with the PSUs granted to executive management is recognized over the vesting period when certain conditions have been met during a three-year service period. For the six months ended June 30, 2011, the Company recognized $12.5 million and $0.9 million, respectively, of compensation expense associated with the 2009 and 2010 PSU plans. No expenses or accruals have been recorded related to the 2011 PSU awards as of June 30, 2011. At the current fair value as of June 30, 2011 and assuming that the Board elects the maximum available payout of 200% for the PSUs for all metrics, total compensation expense related to the PSUs to be recognized during the three-year service periods would be $33.1 million, $12.6 million and $7.7 million, respectively, for the 2009, 2010 and 2011 PSU plans. The total compensation expense will be measured and adjusted quarterly until settlement based on the quarter-end closing common stock prices and the Monte Carlo model valuations. For a more detailed description of the PSU plans, conditions and structure, see our definitive proxy statement filed with respect to our 2011 annual meeting under headings Compensation Discussion and Analysis, and Executive Compensation.

(13) Geographic Area Information

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. Furthermore, as all of the Company s operations are located in the United States, all of the Company s costs are included in one cost pool.

Geographic Area Information

In 2011, the Company has owned oil and natural gas interests in six main geographic areas, all within the United States or its territorial waters. Geographic revenue information below is based on physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

Table of Contents

	Three Months Ended June 30, 2011 (1)	Three Months Ended June 30, 2010 (1)	Six Months Ended June 30, 2011 (1)	Six Months Ended June 30, 2010 (1)
	(In thousands)		(In thousands)	
Natural gas, Oil and NGL Revenue				
Eagle Ford	$ 92,216	$ 17,693	$ 152,157	$ 22,015
South Texas	13,116	18,308	25,792	44,661
California (2)	2,980	17,090	14,930	38,487
Rockies (2)	92	6,496	3,526	15,014
Gulf Coast	825	1,350	1,264	5,500
Other Onshore		1,964		4,495
Total revenue, excluding gains on hedges	$ 109,229	$ 62,901	$ 197,669	$ 130,172

(1) Excludes the effects of hedging gains of $2.3 million and $11.0 million for the three and six months ended June 30, 2011, respectively, and $5.7 million and $8.6 million for the three and six months ended June 30, 2010, respectively.

(2) The Rockies and California assets include the DJ Basin and Sacramento Basin assets. The DJ Basin and Sacramento Basin assets were sold in March 2011 and April 2011, respectively. See Note 3 Property and Equipment. The decline in revenues was primarily due to the divestiture of these assets and suspension of capital programs in these areas that produce primarily from dry gas reservoirs.

(14) Restructuring and Reorganization Costs

In 2010, the Company announced an office closure affecting the Denver office and the restructuring and reorganization of Houston personnel as a result of strategic asset divestitures. All affected positions are located in the United States and as of June 2011, all employees covered under the programs have been terminated.

A before-tax charge of $1.3 million ($0.8 million after-tax) was recorded in the first six months of 2011 as General and administrative costs on the Consolidated Statement of Operations. The associated accrued liability is classified as current on the Consolidated Balance Sheet. Of the expenses incurred during the first six months of 2011, approximately $0.6 million related to severance costs, $0.6 million related to the cease-use of the Denver office space and approximately $0.1 million related to relocation costs. While all future costs associated with the restructuring and reorganization cannot be fully anticipated, the total amount estimated that will be incurred is approximately $5.0 million.

During the six months ended June 30, 2011, the Company made payments of approximately $3.2 million associated with these liabilities.

	Amounts before tax (In thousands)
Balance at January 1, 2011	$ 3,224
Accruals	1,010
Adjustments	287
Payments	(3,221)
Balance at June 30, 2011	$ 1,300

(15) 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, and the subsidiaries of Rosetta Resources Inc. other than the subsidiary guarantors are minor. In addition, there are no restrictions on the ability of Rosetta Resources Inc. to obtain funds from its subsidiaries by dividend or loan. Finally, none of Rosetta Resources Inc. 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 parent company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

Table of Contents

(16) Subsequent Events

On July 27, 2011, the remaining consents for assignment were received or waived related to the Sacramento Basin asset divestiture. As such, final proceeds of $0.8 million were released from the escrow account and provided to the Company.

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, expect, plan, project, intend, anticipate, believe, potential, pursue, target or continue, the negative of 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 its 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, 2010 (the 2010 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:

- the supply and demand for natural gas, oil and NGLs;
- changes in the price of natural gas, oil and NGLs;
- 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 to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;

the occurrence of property acquisitions or divestitures;

reserve levels;

inflation;

competition in the oil and natural gas industry;

the availability and cost of relevant raw materials, goods and services;

the availability and cost of processing and transportation;

changes or advances in technology;

Table of Contents

potential reserve revisions;

limitations, availability, and constraints in infrastructure required to transport, process, and market, natural gas, oil and NGLs;

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

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

drilling and 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;

any other factors that impact or could impact the exploration of oil 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 and natural gas; and

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.

Overview

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010, and material changes in our financial condition since December 31, 2010. This discussion includes the operations of our DJ Basin and Sacramento Basin assets which were divested in March and April 2011, respectively, and should be read in conjunction with our 2010 Annual Report, which includes as part of Management s Discussion and Analysis of Financial Condition and Results of Operations disclosures regarding critical accounting policies.

The following summarizes our performance for the three months ended June 30, 2011 as compared to the same period for 2010:

production on a Bcfe basis increased 20% to 14.6 Bcfe for the three months ended June 30, 2011 from 12.2 Bcfe for the three months ended June 30, 2010;

13 gross (12 net) wells were drilled with a net success rate of 100% for the three months ended June 30, 2011 compared to 58 gross (57 net) wells drilled with a net success rate of 100% for the same period in 2010;

58% of revenue for the three months ended June 30, 2011 was generated from oil and NGL sales as compared to 31% for the same period in 2010, reflecting our shift to a higher total liquids mix;

average realized gas prices, including hedging, increased $1.08 per Mcf, or 23%, to $5.88 per Mcf for the three months ended June 30, 2011 from $4.80 per Mcf for the three months ended June 30, 2010;

average realized oil prices, including hedging, increased $6.88 per Bbl, or 9%, to $80.17 per Bbl for the three months ended June 30, 2011 from $73.29 per Bbl for the three months ended June 30, 2010;

Table of Contents

- average realized NGL prices, including hedging, increased $3.16 per Bbl, or 8%, to $44.79 per Bbl for the three months ended June 30, 2011 from $41.63 per Bbl for the three months ended June 30, 2010;

- total revenue, including the effects of hedging, increased $43.0 million, or 63%, to $111.6 million for the three months ended June 30, 2011 from $68.6 million for the three months ended June 30, 2010; and

- diluted earnings per share increased $0.40 to $0.48 for the three months ended June 30, 2011 from $0.08 for the three months ended June 30, 2010.

The following summarizes our performance for the six months ended June 30, 2011 as compared to the same period for 2010:

- production on a Bcfe basis increased 22% to 28.6 Bcfe for the six months ended June 30, 2011 from 23.4 Bcfe for the six months ended June 30, 2010;

- 24 gross (23 net) wells were drilled with a net success rate of 100% for the six months ended June 30, 2011 compared to 94 gross (92 net) wells drilled with a net success rate of 99% for the same period in 2010;

- 54% of revenue for the six months ended June 30, 2011 was generated from oil and NGL sales as compared to 26% for the same period in 2010, reflecting our shift to a higher total liquids mix;

- average realized gas prices, including hedging, increased $0.26 per Mcf, or 5%, to $5.56 per Mcf for the six months ended June 30, 2011 from $5.30 per Mcf for the six months ended June 30, 2010;

- average realized oil prices, including hedging, increased $7.74 per Bbl, or 10%, to $82.16 per Bbl for the six months ended June 30, 2011 from $74.42 per Bbl for the six months ended June 30, 2010;

- average realized NGL prices, including hedging, increased $1.74 per Bbl, or 4%, to $44.50 per Bbl for the six months ended June 30, 2011 from $42.76 per Bbl for the six months ended June 30, 2010;

- total revenue, including the effects of hedging, increased $69.8 million, or 50%, to $208.6 million for the six months ended June 30, 2011 from $138.8 million for the six months ended June 30, 2010; and

- diluted earnings per share increased $0.47 to $0.69 for the six months ended June 30, 2011 from $0.22 for the six months ended June 30, 2010.

During 2011, Rosetta continues to build upon its success as an unconventional resource player with a portfolio of high-quality shale assets and a project inventory offering the potential for visible and sustainable growth. Our position is the result of a transition which began three years ago as we changed our business model from that of a conventional natural gas producer in more mature U.S. basins to now as an operator in emerging U.S. shale plays, offering a more balanced commodity mix and greater returns and opportunities.

We were an early entrant into the Eagle Ford shale in South Texas, accumulating a significant leasehold position during 2008 and 2009 in the highly-competitive industry play. Our efforts were underpinned with a conservative fiscal approach and a focus on cost control and efficiency. Overall, we now hold approximately 65,000 net acres with roughly 50,000 net acres located in the liquids-rich area of the play. Our 2010 activities were focused in our 26,500-acre position in the Gates Ranch area in Webb County where well results continue to exceed expectations. The Eagle Ford shale has become our largest producing area providing more than 80% of our total production for the three months ended June

30, 2011 and approximately 52% of that amount was from crude oil and natural gas liquids.

Our other shale focus area lies in the Southern Alberta Basin in northwest Montana. Rosetta holds approximately 300,000 net acres in the play that we believe is an analog to the prolific Williston Basin. In late 2009, we began an eleven-well vertical drilling program to assess the commerciality of the play. During the second quarter of 2011, we drilled and completed the last wells of that initiative. The results from that effort have significantly increased our understanding of the play and contributed to the design of a horizontal drilling program that is currently underway. Industry activity continues to grow in the Southern Alberta Basin which is accelerating play delineation as well as establishing the need for local service infrastructure.

Continued well performance significantly in excess of prior estimates has necessitated a mid-year update to our proved reserves. As of June 30, 2011, we had an estimated 969.8 Bcfe of proved reserves, including 458.8 Bcfe of natural gas, 35,900 MBbls of oil and condensate and 49,300 MBbls of NGLs of which 29% is proved developed. These proved reserves represent an increase of 490.5 Bcfe, or 102%, from proved reserves of 479.3 Bcfe at December 31, 2010. During the six months ended June 30, 2011, we replaced 28.6 Bcfe of production with 464.1 Bcfe of reserve additions. This increase resulted primarily from an additional 94 proved undeveloped locations (PUDs) in the Gates Ranch area. Our divestiture results, operating cash flows and development plans all indicate that these reserves will be developed over the next five years. We relied on the following technologies to estimate these reserve additions:

Successfully drilled and completed 35 wells in all lease line directions and interior wells proving a continuous accumulation of hydrocarbons over the entire lease.

Utilized 3-D seismic covering 48% of the Gates Ranch acreage indicating a continuous Eagle Ford formation over this portion of the lease.

Conducted a Micro-seismic evaluation that verified effective stimulation of the reservoir from modern fracturing techniques and proppant materials leading to consistent production results and production histories.

Table of Contents

During the six months ended June 30, 2011, we spent $158.1 million for drilling and completions in the Eagle Ford shale including $84.9 million to reclass reserves from twelve Gates Ranch wells from proved undeveloped (PUD) to proved producing (PDP) for a total reclass of 45.5 Bcfe of reserves. Proved reserves also include a 132.4 Bcfe positive performance revision primarily due to an increase in the estimated ultimate recovery (EUR) of hydrocarbons on thirty-five Gates Ranch wells. Twenty-two of these Gates wells have greater than six months of production history and some of these wells have been producing over 18 months. The decline profiles on wells with significant production history indicate that the EURs are much more likely to increase or remain constant than to decline. The increase in proved reserves was slightly offset by the divestiture of 84.3 Bcfe of estimated proved reserves associated with the DJ Basin and Sacramento Basin asset divestitures.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of June 30, 2011:

	Estimated Proved Reserves at June 30, 2011 (1)(2)									
	Developed				Undeveloped					Percent of
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Total (Bcfe) (3)	Total Reserves
Eagle Ford	87.0	10.3	8.0	196.7	302.9	36.6	27.4	687.1	883.8	91%
South Texas	67.6	2.4	0.4	84.3					84.3	9%
Gulf Coast	0.6			0.8					0.8	0%
Other Onshore	0.7		0.1	0.9					0.9	0%
Total	155.9	12.7	8.5	282.7	302.9	36.6	27.4	687.1	969.8	100%

(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the SEC guidelines and audited by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. NSAI s report is attached as Exhibit 99.1 to this Form 10-Q.

(2) The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average price, calculated as the twelve-month first day of the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The calculated prices as of June 30, 2011 and based on twelve-month first day of the month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil is $86.60 per Bbl and Henry Hub natural gas of $4.21 per MMBtu. The prices used for the December 31, 2010 reporting period was $75.96 per Bbl and $4.38 per MMBtu.

(3) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

The overall metrics of our business have been greatly improved with our success in the Eagle Ford shale. Our lease operating expense per Mcfe declined to $0.82 per Mcfe in the first six months of 2011 from $1.20 per Mcfe for the same period in 2010. In addition, production volume for the first six months of 2011 increased by 22% compared to the same period in 2010, while increasing the higher-valued oil and liquids component to approximately 39 percent of our overall mix for the six months ended June 30, 2011.

With the growth of our shale activities, we have streamlined our operations by divesting of assets that no longer fit our operating model and are redeploying the proceeds of such divestitures into our growth initiatives. In total, we have executed sale agreements for more than $340 million for properties in nine states. In February 2011, we announced the divestiture of assets in the DJ Basin in Colorado and the Sacramento Basin in California for a total sales price of $255 million, subject to customary adjustments. On March 31, 2011, we closed on the sale of our DJ Basin assets and through multiple stages, are closing on the sale of our Sacramento Basin assets which began on April 15, 2011 and continued throughout the current quarter. The completion of the remaining portion of the transaction occurred in the third quarter of 2011. Both of these asset divestitures are effective of as January 1, 2011. At this time, we believe that we have sufficient internal investment opportunities to grow without acquiring additional properties. However, we continue to evaluate opportunities that fit our business model and our strategic and economic objectives.

During the second quarter, we raised our previously announced 2011 capital budget of $360 million to approximately $475 million to take advantage of the timely completion of our divestiture program and accelerate our growth in shale activities. During 2011, we plan approximately 40 completions in the Gates Ranch area and have a fracture stimulation agreement in place to handle this activity. In addition, we intend to test our acreage position outside Gates Ranch that is also located in the liquids portion of the Eagle Ford shale. In the Southern Alberta Basin, we have entered the second phase of our delineation initiative by launching a horizontal drilling program. In total, approximately 85 percent of capital spending will be directed toward development and exploration activities in the Eagle Ford shale. We believe that the program economics of the Eagle Ford shale provide some of the strongest returns among U.S. onshore basins and our progress in the area will further shift our product mix toward a higher percentage of liquids. In addition, we are poised to take advantage of any recovery in natural gas prices with 15,000 net acres of Eagle Ford holdings that lie in the dry-gas window of the play.

As of June 30, 2011, we have completed 40 horizontal wells in the Eagle Ford shale. During the second quarter of 2011, we operated three rigs in the Eagle Ford area completing 9 horizontal wells. We have also identified two pilot areas to initiate infill drilling activity within Gates Ranch. Drilling within the first pilot area has been completed and operations are now underway in the second area. The wells drilled in both pilot areas should be completed and on production by year-end 2011.

The timely and efficient development of our Eagle Ford resources remains challenging in a region where midstream services are in high demand and infrastructure is still under construction. In response, Rosetta has entered into long-term contracts for firm transportation and processing capacity to reduce our exposure to production constraints. We also have secured firm processing capacity agreements with multiple providers to meet our projected growth in volumes from the area. During the second quarter, Rosetta increased its daily transportation capacity from the Eagle Ford shale by 20 percent to 245 MMcf/d of gross wellhead production with 195 MMcf/d contracted to be available by the second quarter of 2012 and total contractual capacity reached by 2013.

While our unconventional resource strategy is proving successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Our business model takes into account the threats that could impede our achievement of our stated growth objectives and the building of our asset base. However, we cannot completely control all external factors that could affect our operating environment. We have diversified our production base toward crude oil and natural gas liquids that continue to be priced at more favorable levels than natural gas. With increasing industry activity in the Eagle Ford shale, our largest producing area, we have taken aggressive steps to ensure access to necessary services and infrastructure.

We announced the closing of our Denver office and the reorganization of Houston personnel starting in 2010. Since the initiation of the reorganization, we have incurred approximately $4.8 million of expenses primarily related to severance costs and the closing of our Denver office. We expect the reorganization to be completed by December 31, 2011 and while all future costs associated with the reorganization cannot be fully anticipated, we expect to incur total costs of approximately $5.0 million. We believe the consolidation of our technical resources to Houston is allowing us to capitalize on the dynamics and efficiencies of operating in a central location.

We believe that we can execute our 2011 capital program from internally generated cash flows, cash on hand and the proceeds from our asset divestitures. We monitor our liquidity continuously and will respond to changing market conditions,

Table of Contents

commodity prices or service costs. If our internal funds were insufficient to meet projected funding requirements, we would consider curtailing our capital spending, drawing on the unused capacity under our existing revolving credit facility or accessing the capital markets.

In May 2011, we amended our Restated Revolver to increase our revolving line of credit to $750.0 million and extended its term until May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements, as well as 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. In April 2011, we used $100.0 million of the proceeds from our asset divestitures to reduce our outstanding debt under the Restated Revolver. As extended, the borrowing base under the Restated Revolver is currently set at $325.0 million with the next semi-annual review scheduled to be completed in October 2011. As of August 2, 2011, we had $30.0 million outstanding, with $295.0 million available for borrowing under the Restated Revolver.

Results of Operations

Revenues

Our revenues are derived from the sale of our natural gas, oil and NGL production, which includes the effects of commodity hedge contracts. Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold.

Total revenue, including the effects of hedging, for the three months ended June 30, 2011 was $111.6 million, which is an increase of $43.0 million, or 63%, from $68.6 million for the three months ended June 30, 2010. Total revenue, excluding the effects of hedging, for the three months ended June 30, 2011 was $109.2 million, which is an increase of $46.3 million, or 74%, from $62.9 million for the three months ended June 30, 2010. Approximately 58% of our revenue for the three months ended June 30, 2011 was attributable to oil and NGL sales as compared to 31% for the same period in 2010.

Total revenue, including the effects of hedging, for the six months ended June 30, 2011 was $208.6 million, which is an increase of $69.8 million, or 50%, from $138.8 million for the six months ended June 30, 2010. Total revenue, excluding the effects of hedging, for the six months ended June 30, 2011 was $197.7 million, which is an increase of $67.5 million, or 52%, from $130.2 million for the six months ended June 30, 2010. Approximately 54% of our revenue for the six months ended June 30, 2011 was attributable to oil and NGL sales as compared to 26% for the same period in 2010.

Table of Contents

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change Increase/ (Decrease)	2011	2010	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Revenues:						
Natural gas sales	$ 46,457	$ 47,491	(2%)	$ 96,237	$ 103,298	(7%)
Oil sales	34,312	10,773	218%	63,061	17,756	255%
NGL sales	30,788	10,358	197%	49,330	17,716	178%
Total revenue	$ 111,557	$ 68,622	63%	$ 208,628	$ 138,770	50%
Production:						
Gas (Bcf)	7.9	9.9	(20%)	17.3	19.5	(11%)
Oil (MBbls)	428.0	147.0	191%	767.5	238.6	222%
NGLs (MBbls)	687.4	248.8	176%	1,108.5	414.3	168%
Total Equivalents (Bcfe)	14.6	12.2	20%	28.6	23.4	22%
$ per unit:						
Avg. natural gas price per Mcf, excluding hedging	$ 4.45	$ 4.22	5%	$ 4.32	$ 4.86	(11%)
Avg. natural gas price per Mcf	5.88	4.80	23%	5.56	5.30	5%
Avg. oil price per Bbl, excluding hedging	93.99	73.29	28%	90.29	74.42	21%
Avg. oil price per Bbl	80.17	73.29	9%	82.16	74.42	10%
Avg. NGL price per Bbl, excluding hedging	49.21	41.63	18%	48.31	42.76	13%
Avg. NGL price per Bbl	44.79	41.63	8%	44.50	42.76	4%
Avg. revenue per Mcfe	7.64	5.62	36%	7.29	5.93	23%

Natural Gas. For the three and six months ended June 30, 2011, natural gas revenue, including the effects of hedging, decreased by $1.0 million and $7.1 million, respectively, from the same periods in 2010. The decrease in both periods was primarily due to the decline in gas production during such periods resulting from the divestitures of certain of our assets that were more gas-based. While gas production declined, the average realized price, including the effects of hedging, increased by $1.08 per Mcf and $0.26 per Mcf, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The effect of natural gas hedging activities on natural gas revenue for the three months ended June 30, 2011 resulted in a gain of $11.3 million as compared to a gain of $5.7 million for the three months ended June 30, 2010. The effect of natural gas hedging activities on natural gas revenue for the six months ended June 30, 2011 resulted in a gain of $21.4 million as compared to a gain of $8.6 million for the six months ended June 30, 2010.

Crude Oil. For the three and six months ended June 30, 2011, oil revenue, including the effects of hedging, increased by $23.5 million and $45.3 million, respectively, from the same periods in 2010. The increase in both periods was attributable to an increase in production of 281.0 MBbls and 528.9 MBbls, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010 due to newly completed wells in the Eagle Ford shale that flowed to sales. In addition to the increase in crude oil production, the average realized price, including the effects of hedging, increased by $6.88 per Bbl and $7.74 per Bbl, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The effect of oil hedging activities on oil revenue for the three and six months ended June 30, 2011 resulted in losses of $5.9 million and $6.2 million, respectively. There was no effect of oil hedging activities on oil revenue for either the three or six months ended June 30, 2010 as no oil derivative transactions settled during the those periods.

NGLs. For the three and six months ended June 30, 2011, NGL revenue, including the effects of hedging, increased by $20.4 million and $31.6 million, respectively, from the same periods in 2010. The increase in both periods was attributable to an increase in production of 438.6 MBbls and 694.2 MBbls, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010 due to newly completed wells in the Eagle Ford shale that flowed to sales. In addition to the increase in NGL production, the average realized price, including the effects of hedging, increased by $3.16 per Bbl and $1.74 per Bbl, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The effect of NGL hedging activities on NGL revenue for the three and six months ended June 30, 2011 resulted in losses of $3.0 million and $4.2 million, respectively. There was no effect of NGL hedging activities on NGL revenue for either the three or six months ended June 30, 2010 as no NGL derivative transactions settled during the those periods.

Table of Contents

Operating Expenses

The following table presents information regarding our operating expenses:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change Increase/ (Decrease)	2011	2010	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)					
Lease operating expense	$ 9,010	$ 13,310	(32%)	$ 23,530	$ 27,987	(16%)
Depreciation, depletion and amortization	33,355	25,719	30%	67,384	49,533	36%
Treating, transportation and marketing	4,875	1,406	247%	8,326	2,887	188%
Production taxes	2,973	1,085	174%	4,629	3,375	37%
General and administrative costs	16,307	11,326	44%	37,377	23,133	62%
$ per unit:						
Avg. lease operating expense per Mcfe	$ 0.62	$ 1.09	(43%)	$ 0.82	$ 1.20	(32%)
Avg. DD&A per Mcfe	2.28	2.11	8%	2.36	2.12	11%
Avg. treating, transportation and marketing per Mcfe	0.33	0.12	175%	0.29	0.12	142%
Avg. production taxes per Mcfe	0.20	0.09	122%	0.16	0.14	14%
Avg. production costs per Mcfe (1)	2.90	3.20	(9%)	3.18	3.31	(4%)
Avg. production costs per Mcfe, excluding taxes (2)	2.76	2.94	(6%)	2.99	3.05	(2%)
Avg. General and administrative costs per Mcfe	1.12	0.93	20%	1.31	0.99	32%
Avg. General and administrative costs per Mcfe, excluding stock-based compensation	0.74	0.78	(5%)	0.74	0.80	(8%)

(1) Production costs per Mcfe includes lease operating expense and depreciation, depletion and amortization (DD&A).
(2) Production costs per Mcfe includes lease operating expense and DD&A and excludes production and ad valorem taxes.

Lease Operating Expense. For the three and six months ended June 30, 2011, lease operating expense decreased $4.3 million and $4.5 million, respectively, compared to the same periods in 2010. The overall decrease was primarily due to lower direct lease operating expense and decreased ad valorem taxes as a result of divesting assets.

Depreciation, Depletion and Amortization. DD&A expense increased $7.6 million and $17.9 million, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The increase was due to an increase in production in both periods in 2011 and increased development costs primarily in the Eagle Ford shale.

Treating, Transportation and Marketing. Treating, transportation and marketing expense increased $3.5 million and $5.4 million, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The increase was a result of increased production primarily in the Eagle Ford shale, where infrastructure is still under construction and services are in high demand.

Production Taxes. Production taxes as a percentage of unhedged natural gas, oil and NGL sales were consistent at 2.7% and 2.3%, respectively, for the three and six months ended June 30, 2011 as compared to 1.7% and 2.6%, respectively, for the same periods in 2010. The decreased rate in the three month period ended June 20, 2010 was due to the additional recording of certain production tax credits in the State of Texas that were not previously recognized.

General and Administrative Costs. General and administrative costs increased $5.0 million and $14.2 million, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010. The increase in both periods was primarily the result of an increase of $3.7 million and $11.8 million, respectively, in stock-based compensation expense as a result of our increased stock price from 2010 to 2011.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other income/expense, net, decreased $3.1 million and $1.0 million, respectively, for the three and six months ended June 30, 2011 from the same periods in 2010.

25

Table of Contents

For the three and six months ended June 30, 2011, the decrease in Total other expense was primarily due to a decrease in Interest expense, net of interest capitalized as a result of our repayment of $100.0 million under the Restated Revolver in April 2011 and due to an increase in capitalized interest due to an increase in the weighted average interest rate. The weighted average interest rate for the three and six months ended June 30, 2011 was 8.65% and 8.04%, respectively, compared to 7.41% and 6.82%, respectively, for the same periods in 2010. This increase in the weighted average interest rate was primarily due to the higher interest rate associated with the Senior Notes.

Provision for Income Taxes

The effective tax rate for the three and six months ended June 30, 2011 was 35.9% and 34.2%, respectively, and the effective tax rate for the three and six months ended June 30, 2010 was 40.8% and 38.5%, respectively. The provision for income taxes for the three months ended June 30, 2011 differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and due the impact of state income taxes. For the six months ended June 30, 2011, the provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and an approximate $0.9 million adjustment for 2010 federal income taxes. The impact of the 2010 tax adjustment was determined to be immaterial to our results of operations in all applicable prior interim and annual periods as well as to the projected results of operations for 2011. As of June 30, 2011 and December 31, 2010, we have no unrecognized tax benefits and 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 all or some portion of the deferred tax assets will not be realized. As of June 30, 2011, we have a deferred tax asset of $128.8 million resulting primarily from the difference between the book basis and tax basis of oil and natural gas properties and net operating loss carryforwards. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards.

In connection with the asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, we concluded that it is more likely than not that the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances were established at December 31, 2010 for these items as well as state NOLs in other jurisdictions in which we previously operated but have since divested of operating assets. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow. We also maintain a revolving line of credit, 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 and natural gas and the success of our development and exploration activities as well as future acquisitions. 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 natural gas, oil and NGL sales are discussed above under Results of Operations Revenues Natural Gas, Results of Operations Revenues Crude Oil, and Results of Operations Revenues NGLs. The majority of our capital expenditures are discretionary and could be curtailed if our cash flows 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.

Senior Secured Revolving Credit Facility. On May 10, 2011, we entered into an amendment to our Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, our senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements, as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including our level of reserves as well as the pricing outlook at the time of the redetermination.

Table of Contents

Therefore, a reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base. The borrowing base under the Restated Revolver is currently set at $325.0 million with the next semi-annual review scheduled to be completed in October 2011.

We utilized a portion of asset divestiture proceeds to repay $100.0 million of outstanding debt under the Restated Revolver on April 21, 2011. As of June 30, 2011, we had $30.0 million outstanding with $295.0 million of available borrowing capacity under the Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of our domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of 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. At June 30, 2011, our current ratio was 3.8 and the leverage ratio was 0.9. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at June 30, 2011.

Second Lien Term Loan. Our amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of June 30, 2011, we had $20.0 million of fixed rate borrowings outstanding bearing interest at 13.75% under the Restated Term Loan. We have the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants as defined in the term loan agreement. We are required under the term loan agreement to maintain a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require us to maintain 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. At June 30, 2011, our reserve coverage ratio was 4.8 and the leverage ratio was 0.9. In addition, we are subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at June 30, 2011.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. The Senior Notes were issued under the Indenture with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit our 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 our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. We used proceeds from the Senior Notes offering to repay $114.0 million outstanding under the Restated Revolver and $80.0 million of variable rate borrowings outstanding under our Restated Term Loan and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, we exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

Table of Contents

Cash Flows

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

	Six Months Ended June 30, 2011	2010
	(In thousands)	
Cash flows provided by operating activities	$ 130,464	$ 75,815
Cash flows provided by (used in) investing activities	67,880	(145,002)
Cash flows (used in) provided by financing activities	(105,300)	24,789
Net increase/(decrease) in cash and cash equivalents	$ 93,044	$ (44,398)

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation and general and administrative expenses. Net cash provided by operating activities continues to be a primary source of liquidity and capital used to finance our capital program.

Cash flows provided by operating activities increased by $54.6 million for the six months ended June 30, 2011 as compared to the same period for 2010. The increase primarily resulted from an increase in production of 22% for the six months ended June 30, 2011 compared to the same period for 2010. In addition, at June 30, 2011, we had a working capital surplus of $70.6 million. This surplus was primarily attributable to the increase in cash and cash equivalents due to the receipt of divestiture proceeds.

Investing Activities. The primary driver of cash provided by (used in) investing activities is asset divestitures and capital spending.

Cash flows provided by investing activities increased by $212.9 million for the six months ended June 30, 2011 as compared to the same period for 2010. The increase is primarily driven by the receipt of sales proceeds from the closing of our DJ Basin and Sacramento Basin asset divestitures offset by capital spending in which we participated in the drilling of 24 gross wells as compared to the drilling of 94 gross wells during the same period in 2010.

Financing Activities. The primary drivers of cash (used in) provided by financing activities are repayments and borrowings on our debt facilities, equity transactions associated with the exercise of stock options and the acquisition of treasury shares from employees and directors to pay tax withholding upon the vesting of restricted stock.

Cash flows used in financing activities increased by $130.1 million for the six months ended June 30, 2011 as compared to the same period for 2010. The net increase is primarily related to the repayment of $100.0 million under the Restated Revolver during the six months ended June 30, 2011 while financing activities in the six months ended June 30, 2010 resulted in net borrowings of $31.0 million under the Restated Term Loan and Restated Revolver.

Capital Expenditures and Requirements

The historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2010 Annual Report and is incorporated herein by reference.

Our capital expenditures for the six months ended June 30, 2011 increased by $39.2 million to $205.2 million, from $166.0 million compared to the same period in 2010. During the six months ended June 30, 2011, we participated in the drilling of 24 gross wells with the majority of these being in the Eagle Ford shale. At current commodity prices, our positive operating cash flow and asset sales proceeds should be sufficient to fund planned capital expenditures for 2011, which are projected to be approximately $475.0 million. Our planned capital expenditures primarily reflect development drilling in the Eagle Ford shale where the vast majority of our planned drilling capital is allocated.

We have the discretion to use our available borrowing base and proceeds from divestitures to fund capital expenditures. We also have the ability to adjust our capital investment plans throughout the remainder of the year in response to market conditions.

Commodity Price Risk and Related Hedging Activities

The energy markets have historically been very volatile and natural gas, oil and NGL prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges natural gas, oil and

Table of Contents

NGL prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis 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 natural gas, oil and NGL fixed price swaps, basis swaps and costless collars for each year through 2013. Our fixed price swap, basis 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 natural gas, oil and NGLs, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected production from existing wells at inception of the hedge instruments.

The following table sets forth the results of commodity fixed price, basis swap and costless collars and interest rate swap derivative settlements:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Natural Gas				
Quantity settled (MMBtu)	4,550,000	2,275,000	9,050,000	4,525,000
Increase in natural gas sales revenue (In thousands) (1) (2)	$ 3,133	$ 5,721	$ 10,404	$ 8,598
Crude Oil				
Quantity settled (Bbl)	309,400		334,200	
Decrease in crude oil sales revenue (In thousands) (3)	$ (5,917)	$	$ (6,238)	$
NGL				
Quantity settled (Bbl)	182,000		245,000	
Decrease in NGL sales revenue (In thousands)	$ (3,039)	$	$ (4,225)	$
Interest Rate Swaps				
(Increase) in interest expense (In thousands)	$	$ (238)	$	$ (490)

(1) For the three months ended June 30, 2011, excludes approximately $8.2 million of realized gain associated with the 2011 termination of derivatives used to hedge production from our divested Sacramento Basin properties.

(2) For the six months ended June 30, 2011, excludes approximately $2.9 million and $8.2 million, respectively, of realized gains associated with the 2011 termination of derivatives used to hedge production from our divested DJ Basin and Sacramento Basin properties.

(3) For the three and six months ended June 30, 2011, includes approximately $4.8 million of unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

In accordance with the authoritative guidance for derivatives, all derivative instruments, not designated as a normal purchase sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions on a quarterly basis, consistent with documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges, if any, are included in other income (expense).

As of June 30, 2011, our commodity hedge positions were with counterparties that were also lenders under our credit facilities. This allows us to secure any margin obligation resulting from a negative change in the fair market value of the derivative contracts with the collateral securing our credit facilities, thus eliminating the need for independent collateral postings. As of June 30, 2011, we had no deposits for collateral in regard to our commodity hedge positions.

Governmental Regulation

Climate Change. Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for some of our produced materials. Such initiatives may contain a cap and trade approach to greenhouse gas regulation, which would require companies to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances

29

declines, the cost would presumably increase. While the prospect for such climate change legislation by the current United States Congress appears to be low, several states have adopted, or are in the process of adopting greenhouse gas reporting or cap-and-trade programs. Therefore, while the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), we would expect our operating costs to increase as we buy additional allowances or embark on emission reduction programs.

Even without further federal legislation, the United States Environmental Protection Agency (EPA) has begun to regulate greenhouse gas emissions. In 2009 and 2010, the EPA promulgated new greenhouse gas reporting rules, requiring certain petroleum and natural gas facilities and facilities that emit more than 25,000 tons per year of carbon dioxide equivalents (CO_2e) to prepare and file annual emission reports. These rules, which are currently in effect and to which some of our facilities are subject, require some data reporting to begin in 2011. In addition, on May 13, 2010, the EPA issued a new tailoring rule, which imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of CO_2e. This rule does not currently affect our operations but may as our operations grow. Finally, the EPA is considering additional rulemaking to apply these requirements to broader classes of emission sources, such as facilities with CO_2e emissions greater than 50,000 tons per year, by 2012, which may apply to some of our facilities. As a result of these regulatory initiatives, our operating costs may increase in compliance with these programs, although we are not situated differently in this respect from our competitors in the industry.

Hydraulic Fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act (SDWA) to subject hydraulic fracturing operations to regulation under the SDWA s Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process, which could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against us. In addition, the EPA is currently undertaking a study of hydraulic fracturing s potential impacts on drinking water and groundwater, with initial research results expected by the end of 2012, and is also developing permitting guidance under the SDWA for hydraulic fracturing activities that use diesel fuels in fracturing fluids. Finally, in 2010, the EPA initiated an enforcement action against a gas well operator in Texas, alleging that the company s wells had caused or contributed to the presence of natural gas in a nearby aquifer. While we are in material compliance with applicable environmental laws and regulations and do not use diesel fuels as one of our hydraulic fracturing fluid components, the increased legislation, regulation or enforcement of hydraulic fracturing operations at the federal level could lead to operational delays, increased operating costs and additional regulatory burdens for our business.

Furthermore, a number of states, local governments and regulatory commissions, have adopted, or are evaluating the adoption of, legislation or regulations that could impose more stringent permitting, disclosure, well construction and wastewater disposal requirements on hydraulic fracturing operations. On June 17, 2011, Texas enacted legislation (HB 3328) requiring the Texas Railroad Commission to promulgate new regulations by July 2013 for gas well operators to publicly disclose the chemicals used in hydraulic fracturing. Additionally, on June 15, 2011, the Montana Board of Oil and Gas Conservation proposed rules that would require the public disclosure of fracturing fluid constituents. While we do not anticipate experiencing a material adverse effect from such disclosure requirements and the outcome for other proposed state, regional and local regulations is uncertain, the increased legislation, regulation or enforcement of hydraulic fracturing at the state, regional or local level could reduce our drilling activity or increase our operating costs.

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 management s belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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

Table of Contents

Critical Accounting Policies and Estimates

In our 2010 Annual Report, we identified our most critical accounting policies upon which our financial condition depends as those relating to oil and natural gas reserves, full cost method of accounting, derivative transactions and hedging activities, fair value measurements, revenue recognition, income taxes and stock-based compensation.

We assess the impairment for oil and natural gas properties under the full cost accounting method on a quarterly basis by using a ceiling test to determine if impairment is necessary. If the net capitalized costs of oil and natural gas properties exceed the cost ceiling, we are subject to a ceiling test write-down to the extent of such excess. A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, it would reduce earnings and impact shareholders equity in the period of occurrence and could result in a lower depreciation, depletion and amortization expense in the future.

Our ceiling test was calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of gas and oil at June 30, 2011, based on a Henry Hub gas price of $4.21 per MMBtu and a West Texas Intermediate oil price of $86.60 per Bbl (adjusted for basis and quality differentials). Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded at June 30, 2011. It is possible that a write-down of our oil and gas properties could occur in the future should oil and natural gas prices decline, we experience significant downward adjustments to the estimated proved reserves and/or our commodity hedges settle and are not replaced.

We enter into derivative transactions to hedge against changes in natural gas, oil and NGL prices primarily through the use of fixed price swap agreements, basis swap agreements, costless collars and put options. Consistent with our hedge policy, we entered into a series of derivative transactions to hedge a portion of our expected natural gas, oil and NGL production through 2013. As of June 30, 2011, approximately 100% of total hedged natural gas transactions represented hedged prices of natural gas at the Houston Ship Channel, 66% of hedged crude oil transactions represented hedged prices of crude oil at the West Texas Intermediate on the NYMEX, with the remaining 34% at Light Louisiana Sweet and approximately 59% of the total hedged NGL transactions represented hedged NGL prices at Mont Belvieu Propane (Non-TET) OPIS and Mont Belvieu Natural Gasoline (Non-TET) OPIS.

We utilize counterparty and third party broker quotes to determine the valuation of our derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant NYMEX futures contracts and exchange traded contracts, if deemed necessary, for each derivative settlement location. We have used this valuation technique since the adoption of the authoritative guidance for fair value measurements on January 1, 2008, and we have made no changes or adjustments to our technique since then. We mark to market on a quarterly basis.

Recent Accounting Developments

For a discussion of recent accounting developments, see Note 2 to the Consolidated Financial Statements (Unaudited) in Part I. Item 1. Financial Statements of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk primarily related to adverse changes in natural gas, oil and NGL 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 Disclosure About Market Risk in our 2010 Annual Report and Note 4 Commodity Hedging Contracts and Other Derivatives included in Part I. Item 1. Financial Statements of this Form 10-Q.

As of June 30, 2011, we had open natural gas derivative hedges in an asset position with a fair value of $16.4 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $6.6 million, while a 10 percent decrease in natural gas prices would increase the fair value by approximately $7.0 million. The effects of these derivative transactions on our natural gas sales are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues Natural Gas .

As of June 30, 2011, we had open crude oil derivative hedges in a liability position with a fair value of $13.8 million. A 10 percent increase in crude oil prices would reduce the fair value by approximately $19.5 million, while a 10 percent decrease in crude oil prices would increase the fair value by approximately $14.0 million. The effects of these derivative transactions on our crude oil sales are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues Crude Oil .

Table of Contents

As of June 30, 2011, we had open NGL derivative hedges in a liability position with a fair value of $13.2 million. A 10 percent increase in NGL prices would reduce the fair value by approximately $8.2 million, while a 10 percent decrease in NGL prices would increase the fair value by approximately $8.2 million. The effects of these derivative transactions on our NGL sales are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues NGLs .

These fair value changes assume volatility based on prevailing market parameters at June 30, 2011.

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

Our current cash flow hedge and non-qualifying derivative positions are with counterparties who are lenders in our credit facilities. This arrangement eliminates the need for independent collateral postings with respect to any margin obligation resulting from a negative change in fair market value of the derivative contracts in connection with our hedge related credit obligations. As of June 30, 2011, we had no deposits for collateral in regards to commodity hedge positions. Our derivative instrument assets and liabilities relate to commodity hedges that represent the difference between hedged prices and market prices on hedged volumes of the commodities as of June 30, 2011. We evaluated non-performance risk using the current credit default swaps value and default probabilities for the Company and counterparties and recorded a downward adjustment to the fair value of our derivative liabilities in the amount of $0.2 million at June 30, 2011.

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, 2011. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2011, 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.

During the quarter ended June 30, 2011, we implemented both a volume production software tool and an oil and gas reserves reporting tool, both of which are replacing existing software. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included procedures to preserve the integrity of the data converted and a review by management to validate the data converted. Additionally, we provided training related to these system software tools to individuals using the systems to carry out their job responsibilities, as well as to those who rely on the information. We anticipate that the implementation of these modules will strengthen the overall systems of internal controls due to enhanced automation and integration of related processes. We are modifying the design and documentation of internal control processes and procedures relating to the new modules to supplement and complement existing internal control over certain respective job areas. The system changes were undertaken to integrate systems and consolidate information and were not undertaken in response to any actual or perceived deficiencies in our internal control over financial reporting. Testing of the controls related to the new systems is ongoing and is included in the scope of our assessment of our internal control over financial reporting for 2011.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

We are party to various legal and regulatory proceedings arising in the ordinary course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of negative outcome(s) as to any one or more of these proceedings, the liability we may ultimately incur with respect to any one or more of these matters may be in excess of amounts currently accrued with respect to such matters. Net of our and, as applicable, third parties , available insurance and the performance of contractual defense and indemnity rights and obligations, where applicable, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

32

Table of Contents

Item 1A. Risk Factors

Except as disclosed below, there have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2010 Annual Report.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. Final rules have not yet been issued, and the comment period for some of the proposed rules were recently extended to allow for more comment from interested parties. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. The new requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in natural gas, oil and NGL commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Market conditions or transportation impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions, the unavailability of satisfactory oil, natural gas and natural gas liquids processing and transportation for available markets by product or the remote location of certain of our drilling operations may hinder our access to these markets or delay our production. The availability of a ready market for these various products depends on a number of factors, including the demand for and supply of oil, condensate, natural gas and natural gas liquids and the proximity of reserves to pipelines, terminals and trucking, railroad and/or barge transportation, and processing facilities. Our ability to market our production also depends in substantial part on the availability and capacity of gathering systems, pipelines, terminals, other means of transportation and processing facilities. We may be required to shut in natural gas wells or delay production for lack of a market or because of inadequacy or unavailability of natural gas gathering systems, pipelines, or other means of transportation or processing facilities. The transportation of our gas may be interrupted under the terms of our interruptible or short term transportation agreements due to capacity constraints on the applicable system. The transportation of our gas may be interrupted under the terms of our firm long term transportation, terminal and processing agreements due to operational upset, third party force majeure or other events beyond the Company s control. Further, any disruption of third-party facilities due to maintenance, repairs, debottlenecking, expansion projects, weather or other interruptions of service could negatively impact our ability to market and deliver our products. Our concentration of operations in certain geographic areas, such as the Eagle Ford shale, increases these risks and the potential impact upon us. If we experience any interruptions to the transportation and/or processing of our products, we may be unable to realize revenue from our wells until our production can be tied to a pipeline or gathering system, transported by truck, rail and/or barge, or processed, as applicable into the particular products. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil, condensate, natural gas and natural gas liquids and realization of revenues.

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, 2011:

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	3,393	$ 46.03		
May 1 - May 31	9,913	43.24		
June 1 - June 30	1,372	48.84		
Total	14,678	$ 44.41		

(1) All of the shares were surrendered by our employees and directors to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we 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. Removed and Reserved

Item 5. Other Information

Continued well performance significantly in excess of prior estimates has necessitated a mid-year update to the Company s proved reserves. As of June 30, 2011, the Company had an estimated 969.8 Bcfe of proved reserves, including 458.8 Bcfe of natural gas, 35,900 MBbls of oil and condensate and 49,300 MBbls of NGLs of which 29% is proved developed. These proved reserves represent an increase of 490.5 Bcfe, or 102%, from proved reserves of 479.3 Bcfe at December 31, 2010. During the six months ended June 30, 2011, the Company replaced 28.6 Bcfe of production with 464.1 Bcfe of reserve additions. This increase resulted primarily from an additional 94 proved undeveloped locations (PUDs) in the Gates Ranch area. The Company s divestiture results, operating cash flows and development plans all indicate that these reserves will be developed over the next five years. The Company relied on the following technologies to estimate these reserve additions:

Successfully drilled and completed 35 wells in all lease line directions and interior wells proving a continuous accumulation of hydrocarbons over the entire lease.

Utilized 3-D seismic covering 48% of the Gates Ranch acreage indicating a continuous Eagle Ford formation over this portion of the lease.

Conducted a Micro-seismic evaluation that verified effective stimulation of the reservoir from modern fracturing techniques and proppant materials leading to consistent production results and production histories.

During the six months ended June 30, 2011, the Company spent $158.1 million for drilling and completions in the Eagle Ford shale including $84.9 million to reclass reserves from twelve Gates Ranch wells from proved undeveloped (PUD) to proved producing (PDP) for a total reclass of 45.5 Bcfe of reserves. Proved reserves also include a 132.4 Bcfe positive performance revision primarily due to an increase in the estimated ultimate recovery (EUR) of hydrocarbons on thirty-five Gates Ranch wells. Twenty-two of these Gates wells have greater than six months of production history and some of these wells have been producing over 18 months. The decline profiles on wells with significant production history indicate that the EURs are much more likely to increase or remain constant than to decline. The increase in proved reserves was slightly offset by the divestiture of 84.3 Bcfe of estimated proved reserves associated with the DJ Basin and Sacramento Basin asset divestitures.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of June 30, 2011:

	Estimated Proved Reserves at June 30, 2011 (1)(2)									
	Developed				Undeveloped					
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe)(3)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe)(3)	Total (Bcfe)(3)	Percent of Total Reserves
Eagle Ford	87.0	10.3	8.0	196.7	302.9	36.6	27.4	687.1	883.8	91%
South Texas	67.6	2.4	0.4	84.3					84.3	9%
Gulf Coast	0.6			0.8					0.8	0%
Other Onshore	0.7		0.1	0.9					0.9	0%

Total	155.9	12.7	8.5	282.7	302.9	36.6	27.4	687.1	969.8	100%

(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the SEC guidelines and audited by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. See Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations. NSAI s report is attached as Exhibit 99.1 to this Form 10-Q.

(2) The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average price, calculated as the twelve-month first day of the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The calculated prices as of June 30, 2011 and based on twelve-month first day of the month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil is $86.60 per Bbl and Henry Hub natural gas of $4.21 per MMBtu. The prices used for the December 31, 2010 reporting period was $75.96 per Bbl and $4.38 per MMBtu.

(3) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

Item 6. Exhibits

Exhibit Number	Description
10.1	Fourth Amendment to Amended and Restated Credit Agreement, dated effective as of May 10, 2011, among Rosetta Resources Inc., BNP Paribas and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
23.1*	Consent of Netherland, Sewell & Associates, Inc.
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.
99.1*	Report of Netherland, Sewell & Associates, Inc.

* 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/ MICHAEL J. ROSINSKI
Michael J. Rosinski
Executive Vice President, Chief Financial Officer and Treasurer

(Duly Authorized Officer and Principal Financial Officer)

Date: August 8, 2011

ROSETTA RESOURCES INC.

EXHIBIT INDEX

Exhibit Number	Description
10.1	Fourth Amendment to Amended and Restated Credit Agreement, dated effective as of May 10, 2011, among Rosetta Resources Inc., BNP Paribas and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
23.1*	Consent of Netherland, Sewell & Associates, Inc.
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.
99.1*	Report of Netherland, Sewell & Associates, Inc.

* Filed herewith