

Rosetta Resources Inc.  
Form 10-Q  
November 07, 2011  
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**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 September 30, 2011**

OR

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

**ROSETTA RESOURCES INC.**

(Exact name of registrant as specified in its charter)

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<b>Delaware</b> (State or other jurisdiction of incorporation or organization)	<b>43-2083519</b> (I.R.S. Employer Identification No.)
<b>717 Texas, Suite 2800, Houston, TX</b> (Address of principal executive offices) (Registrant's telephone number, including area code) (713) 335-4000	<b>77002</b> (Zip Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  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 or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-Accelerated filer <input type="checkbox"/> (Do not check if a smaller reporting company)	Smaller Reporting Company <input type="checkbox"/>

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

The number of shares of the registrant's Common Stock, \$.001 par value per share, outstanding as of October 31, 2011 was 53,031,791.

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**Table of Contents****PART I. FINANCIAL INFORMATION****Item 1. Financial Statements****Rosetta Resources Inc.****Consolidated Balance Sheet****(In thousands, except par value and share amounts)**

	<b>September 30, 2011 (Unaudited)</b>	<b>December 31, 2010</b>
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	\$ 106,868	\$ 41,634
Accounts receivable, net	56,007	36,159
Derivative instruments	14,775	19,145
Prepaid expenses	3,332	2,711
Other current assets	5,145	5,454
Total current assets	186,127	105,103
Oil and natural gas properties, full cost method, of which \$120,124 thousand at September 30, 2011 and \$91,148 thousand at December 31, 2010 were excluded from amortization	2,326,302	2,262,161
Other fixed assets	16,030	14,459
	2,342,332	2,276,620
Accumulated depreciation, depletion, and amortization, including impairment	(1,628,160)	(1,546,631)
Total property and equipment, net	714,172	729,989
Deferred loan fees	9,093	7,652
Deferred tax asset	101,248	142,710
Derivative instruments	9,869	1,523
Other assets	2,541	2,463
Total other assets	122,751	154,348
Total assets	\$ 1,023,050	\$ 989,440
<b>Liabilities and Stockholders Equity</b>		
Current liabilities:		
Accounts payable	\$ 168	\$ 3,669
Accrued liabilities	123,783	57,006
Royalties payable	26,295	14,542
Deferred income taxes	5,690	7,132
Total current liabilities	155,936	82,349
Long-term liabilities:		
Derivative instruments		1,011
Long-term debt	250,000	350,000
Other long-term liabilities	9,333	27,264

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Total liabilities	415,269	460,624
Commitments and Contingencies (Note 9)		
Stockholders' equity:		
Preferred stock, \$0.001 par value; authorized 5,000,000 shares; no shares issued in 2011 or 2010		
Common stock, \$0.001 par value; authorized 150,000,000 shares; issued 52,488,193 shares and 52,031,004 shares at September 30, 2011 and December 31, 2010, respectively		
	52	52
Additional paid-in capital	801,429	793,293
Treasury stock, at cost; 445,479 and 343,093 shares at September 30, 2011 and December 31, 2010, respectively	(11,103)	(6,896)
Accumulated other comprehensive income	17,950	11,259
Accumulated deficit	(200,547)	(268,892)
Total stockholders' equity	607,781	528,816
Total liabilities and stockholders' equity	\$ 1,023,050	\$ 989,440

The accompanying notes to the financial statements are an integral part hereof.

**Table of Contents****Rosetta Resources Inc.****Consolidated Statement of Operations****(In thousands, except per share amounts)****(Unaudited)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
<b>Revenues:</b>				
Natural gas sales	\$ 33,256	\$ 53,783	\$ 129,493	\$ 157,081
Oil sales	31,590	15,406	94,651	33,162
NGL sales	36,411	11,078	85,741	28,794
<b>Total revenues</b>	<b>101,257</b>	<b>80,267</b>	<b>309,885</b>	<b>219,037</b>
<b>Operating costs and expenses:</b>				
Lease operating expense	4,445	11,486	27,975	39,473
Depreciation, depletion, and amortization	24,657	32,163	92,041	81,696
Treating, transportation and marketing	5,481	1,878	13,807	4,765
Production taxes	2,107	1,565	6,736	4,940
General and administrative costs	9,453	12,560	46,830	35,693
<b>Total operating costs and expenses</b>	<b>46,143</b>	<b>59,652</b>	<b>187,389</b>	<b>166,567</b>
<b>Operating income</b>	<b>55,114</b>	<b>20,615</b>	<b>122,496</b>	<b>52,470</b>
<b>Other (income) expense:</b>				
Interest expense, net of interest capitalized	5,238	6,575	16,650	20,367
Interest (income)	(5)		(38)	(29)
Other expense (income), net	88	(149)	742	(883)
<b>Total other expense</b>	<b>5,321</b>	<b>6,426</b>	<b>17,354</b>	<b>19,455</b>
<b>Income before provision for income taxes</b>	<b>49,793</b>	<b>14,189</b>	<b>105,142</b>	<b>33,015</b>
Income tax expense	17,845	5,339	36,797	12,590
<b>Net income</b>	<b>\$ 31,948</b>	<b>\$ 8,850</b>	<b>\$ 68,345</b>	<b>\$ 20,425</b>
<b>Earnings per share:</b>				
Basic	\$ 0.61	\$ 0.17	\$ 1.32	\$ 0.40
Diluted	\$ 0.61	\$ 0.17	\$ 1.30	\$ 0.39
<b>Weighted average shares outstanding:</b>				
Basic	52,038	51,411	51,962	51,329
Diluted	52,627	52,073	52,593	52,050

The accompanying notes to the financial statements are an integral part hereof.



**Table of Contents****Rosetta Resources Inc.****Consolidated Statement of Cash Flows****(In thousands)****(Unaudited)**

	<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>
Cash flows from operating activities		
Net income	\$ 68,345	\$ 20,425
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	92,041	81,696
Deferred income taxes	36,547	12,282
Amortization of deferred loan fees recorded as interest expense	1,730	2,222
Amortization of original issue discount recorded as interest expense		1,258
Stock-based compensation expense	15,380	7,894
Commodity derivative (income) expense	(4,208)	
Change in operating assets and liabilities:		
Accounts receivable	(19,848)	2,168
Prepaid expenses	(596)	(68)
Other current assets	309	624
Other assets	(79)	(296)
Accounts payable	(3,501)	(833)
Accrued liabilities	3,375	10,364
Royalties payable	11,755	(4,185)
Other long-term liabilities	(8,866)	
Derivative instruments	9,386	
Net cash provided by operating activities	201,770	133,551
Cash flows from investing activities		
Acquisitions of oil and gas properties		(5,850)
Additions of oil and gas assets	(271,770)	(243,066)
Disposals of oil and gas properties and assets	240,620	14,872
Net cash (used in) investing activities	(31,150)	(234,044)
Cash flows from financing activities		
Payments on Restated Term Loan		(80,000)
Borrowings on Restated Revolver		64,000
Payments on Restated Revolver	(100,000)	(114,000)
Issuance of Senior Notes		200,000
Deferred loan fees	(3,197)	(6,228)
Proceeds from stock options exercised	2,017	1,786
Purchases of treasury stock	(4,206)	(2,079)
Net cash (used in) provided by financing activities	(105,386)	63,479
Net increase (decrease) in cash	65,234	(37,014)
Cash and cash equivalents, beginning of period	41,634	61,256

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Cash and cash equivalents, end of period	\$ 106,868	\$ 24,242
Supplemental disclosures:		
Capital expenditures included in accrued liabilities	\$ 80,045	\$ 20,461

The accompanying notes to the financial statements are an integral part hereof.

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**Rosetta Resources Inc.**

**Notes to Consolidated Financial Statements (unaudited)**

**(1) Organization and Operations of the Company**

*Nature of Operations.* Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent oil and gas company engaged in onshore oil and natural gas exploration, development, production and acquisition activities in the United States of America. The Company's operations are concentrated in South Texas, primarily in the Eagle Ford shale, and in the Southern Alberta Basin in northwest Montana.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of only normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. These financial statements and notes should be read in conjunction with the Company's audited Consolidated Financial Statements and the notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2010 (2010 Annual Report).

Certain reclassifications of prior year balances have been made to conform them to the current year presentation. These reclassifications have no impact on net income.

**(2) Summary of Significant Accounting Policies**

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2010 Annual Report.

***Recent Accounting Developments***

The following recently issued accounting developments have been applied or may impact the Company in future periods.

*Fair Value Measurements.* In January 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures were required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. This guidance requires additional disclosures but did not impact the Company's consolidated financial position, results of operations or cash flows. See Note 5 Fair Value Measurements.

In April 2011, the FASB further expanded authoritative guidance clarifying common requirements for measuring fair value instruments and for disclosing information about fair value measurements in accordance with U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). In this guidance, the FASB clarifies that the concept of highest and best use and valuation premise in a fair value measurement is only relevant when measuring the fair value of nonfinancial assets and is not relevant when measuring the fair value of financial assets or liabilities. The FASB also addressed measuring the fair value of an instrument classified in shareholders equity whereby an entity should measure the fair value of its own equity instrument from the perspective of a market participant. In addition, this guidance requires disclosure of quantitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is not permitted. This guidance will require additional disclosures but will not impact the Company's consolidated financial position, results of operations or cash flows.

*Comprehensive Income.* In September 2011, the FASB issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate and consecutive statements. Irrespective of the presentation method chosen, an entity will be required to present on the face of the financial statement reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the component is presented. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is permitted.

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This guidance will require presentation adjustments to the face of the Company's consolidated financial statements, including historical periods, but will not impact the Company's consolidated financial position, results of operations or cash flows.

**Table of Contents****(3) Property and Equipment**

The Company's total property and equipment consists of the following:

	September 30, 2011	December 31, 2010
	(In thousands)	
Proved properties	\$ 2,175,647	\$ 2,124,615
Unproved/unevaluated properties	120,124	91,148
Gas gathering system and compressor stations	30,531	46,398
Other fixed assets	16,030	14,459
<b>Total property and equipment, gross</b>	<b>2,342,332</b>	<b>2,276,620</b>
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,628,160)	(1,546,631)
<b>Total property and equipment, net</b>	<b>\$ 714,172</b>	<b>\$ 729,989</b>

On February 22, 2011, the Company executed a purchase and sale agreement for \$55.0 million for the divestiture of the DJ Basin assets in Colorado. The sale of these assets closed on March 31, 2011 with an effective date of January 1, 2011. The agreement was subject to due diligence and post-closing purchase price adjustments. Proceeds from the divestiture were recorded as an adjustment to the full cost pool with no gain or loss recognized.

Subsequently on February 24, 2011, the Company executed a purchase and sale agreement for \$200.0 million for the divestiture of the Sacramento Basin assets in California. The sale of these assets initially closed on April 15, 2011 with an effective date of January 1, 2011 and was subject to post-closing purchase price adjustments. Approximately \$43.6 million associated with a certain portion of the properties was placed in escrow pending the Company's receipt of appropriate consents for assignment. During the second and third quarters of 2011, the Company closed on the remaining properties for which consents for assignment were received or waived. Final proceeds were then released from the escrow account and provided to the Company. Proceeds from the divestiture were recorded as an adjustment to the full cost pool with no gain or loss recognized.

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized \$1.1 million and \$2.3 million of internal costs for the three months ended September 30, 2011 and 2010, respectively, and \$3.5 million and \$6.2 million for the nine months ended September 30, 2011 and 2010, respectively.

Oil and gas properties include costs of \$120.1 million and \$91.1 million as of September 30, 2011 and December 31, 2010, respectively, which were excluded from amortized capitalized costs. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest. The increase from December 31, 2010 to September 30, 2011 is the result of an increase in exploratory drilling costs primarily in the Southern Alberta Basin and in the Eagle Ford shale.

At June 30, 2011, a mid-year update to the Company's proved reserves was announced due to continued well performance significantly in excess of prior estimates. In the previous update, the Company estimated 969.8 Bcfe of proved reserves, of which 29% was proved developed as of June 30, 2011. These proved reserves represented an increase of 102% from proved reserves of 479.3 Bcfe at December 31, 2010. This increase resulted primarily from additional proved undeveloped locations ( PUDs ) in the Gates Ranch area. Divestiture results, operating cash flows and development plans all indicate that these reserves will be developed within five years from the date recorded as a proved undeveloped reserve.

The quantity of proved reserves is a significant input to the calculated depletion rate (depletion per Mcfe). Holding all other factors constant, an upward revision in the quantity of proved reserves will alter the relationship between the cost of developing reserves and the related reserve quantity and will result in a lower depletion rate. This upward revision in reserves as of June 30, 2011 resulted in a decrease in the depletion rate of approximately 24% for the three months ended September 30, 2011.

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Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its oil and gas assets within each separate cost center. The Company's ceiling test was calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of gas and oil as of September 30, 2011, which were based on a Henry Hub gas price of \$4.16 per MMBtu and a West Texas Intermediate oil price of \$91.00 per Bbl (adjusted for basis and quality differentials), respectively. 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 September 30, 2011. It is possible that a write-down of the Company's oil and gas properties could occur in the event that oil and natural gas prices decline, the Company experiences significant downward adjustments to its estimated proved reserves and/or the Company's commodity hedges settle and are not replaced.

In 2010, the Company's ceiling test was also calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of gas and oil as of September 30, 2010, which were based on a Henry Hub gas price of \$4.41 per MMBtu and a West Texas Intermediate oil price of \$73.85 per Bbl (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount also exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded at September 30, 2010.

### **(4) Commodity Hedging Contracts and Other Derivatives**

The Company is exposed to various market risks, including volatility in natural gas, oil and natural gas liquid ( NGL ) commodity prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategy and available derivative prices. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company's natural gas, oil and NGL production. Interest rate swaps were utilized in 2010 to manage interest rate risk associated with the Company's previous variable-rate borrowings. These interest rate swaps settled during 2010 and the Company has not entered into any interest rate swaps during 2011.

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, New York Mercantile Exchange ( NYMEX ) roll swaps and costless collars. Many of these derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, while the Company's crude oil basis and NYMEX roll swaps meet the objective of managing commodity price exposure, these trades do not qualify for hedge accounting. As a result, these derivative financial instruments are referred to as non-qualifying.

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At September 30, 2011, the following financial fixed price swap, basis swap, NYMEX roll swap and costless collar transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Fair Market Value Asset/(Liability) (In thousands)
Natural gas	2011	Swap	Cash flow	15,000	1,380,000	\$ 5.99	\$	\$ 3,094
Natural gas	2011	Costless Collar	Cash flow	35,000	3,220,000	5.63	7.27	6,035
Natural gas	2012	Costless Collar	Cash flow	20,000	7,320,000	5.13	6.31	7,651
					11,920,000			\$ 16,780

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
Crude oil	2011	Costless Collar	Cash flow	3,400	312,800	\$ 75.59	\$ 103.29	\$ 916
Crude oil	2012	Costless Collar	Cash flow	5,000	1,830,000	75.60	112.56	11,797
Crude oil	2013	Costless Collar	Cash flow	3,750	1,368,750	75.00	122.81	9,534
					3,511,550			\$ 22,247

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
NGL Propane	2011	Swap	Cash flow	1,000	92,000	\$ 47.98	\$	\$ (1,883)
NGL Isobutane	2011	Swap	Cash flow	270	24,840	64.02		(594)
NGL Normal Butane	2011	Swap	Cash flow	330	30,360	63.79		(544)
NGL Pentanes Plus	2011	Swap	Cash flow	400	36,800	83.04		(496)
NGL Propane	2012	Swap	Cash flow	1,000	366,000	47.20		(3,121)
NGL Isobutane	2012	Swap	Cash flow	260	95,160	66.63		(542)
NGL Normal Butane	2012	Swap	Cash flow	280	102,480	65.30		(498)
NGL Pentanes Plus	2012	Swap	Cash flow	410	150,060	86.62		(20)
					897,700			\$ (7,698)

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per	Average Ceiling Prices per	Fair Market Value Asset/(Liability) (In thousands)
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						Bbl	Bbl	
Crude oil	May 2012- December 2012	Basis Swap	Non-qualifying	2,500	612,500	\$ 8.70	\$	\$ (3,796)
Crude oil	May 2012- December 2012	NYMEX Roll Swap	Non-qualifying	2,500	612,500	(0.30)		29
Crude oil	2013	Basis Swap	Non-qualifying	1,875	684,375	5.80		(2,927)
Crude oil	2013	NYMEX Roll Swap	Non-qualifying	1,875	684,375	(0.18)		9
					2,593,750		\$	(6,685)

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The Company's current cash flow hedge and non-qualifying derivative positions are with counterparties who are lenders under the Company's credit facilities. This allows the Company to satisfy any need for any margin obligation resulting from a negative change in fair market value of the derivative contracts with the collateral securing its credit facilities, thus eliminating the need for independent collateral postings. As of September 30, 2011, the Company had no deposits for collateral in regard to commodity hedge positions.

The following table sets forth the results of derivative settlements for the respective periods as reflected in the Consolidated Statement of Operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
<b>Natural Gas</b>				
Quantity settled (MMBtu)	4,600,000	5,060,000	13,650,000	9,585,000
Increase in natural gas sales revenue (In thousands) (1)	\$ 2,450	\$ 10,460	\$ 12,854	\$ 19,058
<b>Crude Oil</b>				
Quantity settled (Bbl)	312,800		647,000	
Decrease in crude oil sales revenue (In thousands) (2)	\$ (181)	\$	\$ (1,635)	\$
<b>NGL</b>				
Quantity settled (Bbl)	184,000		429,000	
Decrease in NGL sales revenue (In thousands)	\$ (3,178)	\$	\$ (7,403)	\$
<b>Interest Rate Swaps</b>				
(Increase) in interest expense (In thousands)	\$	\$ (237)	\$	\$ (727)

(1) For the nine months ended September 30, 2011, excludes approximately \$11.1 million 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.

(2) For the three and nine months ended September 30, 2011, excludes approximately \$1.9 million and \$6.7 million, respectively, of unrealized loss associated with the change in fair value of the Company's crude oil basis and NYMEX roll swaps.

As of September 30, 2011, the Company expects to reclassify net gains of \$14.8 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 September 30, 2011.

**Additional Disclosures about Derivative Instruments and Hedging Activities**

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.

**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

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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 September 30, 2011, the Company had outstanding natural gas, oil and NGL commodity forward contracts with notional volumes of 11,920,000 MMBtus, 6,105,300 Bbls and 897,700 Bbls, respectively, that were entered into to hedge forecasted natural gas, oil and NGL sales.

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

		<b>Fair Values of Derivative Instruments</b>	
		<b>Derivative Assets (Liabilities)</b>	
<b>Balance Sheet Location</b>		<b>Fair Value</b>	
		<b>September 30, 2011</b>	<b>December 31, 2010</b>
		(In thousands)	
<b>Derivatives designated as hedging instruments</b>			
Commodity contracts - natural gas	Derivative instruments - current assets	\$ 15,132	\$ 24,959
Commodity contracts - natural gas	Derivative instruments - non-current assets	1,648	3,614
Commodity contracts - crude oil	Derivative instruments - current assets	9,071	(2,696)
Commodity contracts - crude oil	Derivative instruments - non-current assets	13,176	(2,207)
Commodity contracts - NGL	Derivative instruments - current assets	(6,610)	(3,118)
Commodity contracts - NGL	Derivative instruments - non-current assets	(1,088)	116
Commodity contracts - NGL	Derivative instruments - long-term liabilities		(1,011)
<b>Total derivatives designated as hedging instruments</b>		<b>\$ 31,329</b>	<b>\$ 19,657</b>
<b>Derivatives not designated as hedging instruments</b>			
Commodity contracts - crude oil	Derivative instruments - current assets	\$ (2,818)	\$
Commodity contracts - crude oil	Derivative instruments - non-current assets	(3,867)	
<b>Total derivatives not designated as hedging instruments</b>		<b>\$ (6,685)</b>	<b>\$</b>
<b>Total derivatives</b>		<b>\$ 24,644</b>	<b>\$ 19,657</b>

<b>Derivatives in Cash Flow Hedging Relationships</b>	<b>Amount Recognized in OCI on Derivative (Effective Portion)</b>			
	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30, 2011</b>	<b>September 30, 2010</b>	<b>September 30, 2011</b>	<b>September 30, 2010</b>
(In thousands)				
Commodity contracts - natural gas	\$ 7,264	\$ 20,663	\$ 9,342	\$ 54,223
Commodity contracts - crude oil	30,969	(868)	25,516	(868)
Commodity contracts - NGL	2,473	(1,354)	(9,985)	(1,354)
Interest rate swap		(90)		(338)
<b>Total</b>	<b>\$ 40,706</b>	<b>\$ 18,351</b>	<b>\$ 24,873</b>	<b>\$ 51,663</b>

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Location of Gain or (Loss)	Amount Reclassified from Accumulated OCI into Income (Effective Portion)			
	Three Months Ended		Nine Months Ended	
	September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
	(In thousands)			
Natural gas sales	\$ 2,450	\$ 10,460	\$ 12,854	\$ 19,058
Crude oil sales	(181)		(1,635)	
NGL sales	(3,178)		(7,403)	
Interest expense, net of interest capitalized		(237)		(727)
<b>Total</b>	<b>\$ (909)</b>	<b>\$ 10,223</b>	<b>\$ 3,816</b>	<b>\$ 18,331</b>

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		Nine Months Ended	
	September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
	(In thousands)			
Natural gas sales (1)	\$	\$	\$ 11,018	\$
Crude oil sales (2)	(1,901)		(6,685)	
NGL sales				
<b>Total</b>	<b>\$ (1,901)</b>	<b>\$</b>	<b>\$ 4,333</b>	<b>\$</b>

- (1) For the nine months ended September 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.
- (2) For the three and nine months ended September 30, 2011, these amounts represent the 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 September 30, 2011, and as 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 September 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.

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.

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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 September 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 NYMEX futures contracts and exchange traded contracts for each derivative settlement location.

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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 September 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.

	<b>Fair value as of September 30, 2011</b>			
	Level 1	Level 2	Level 3 (In thousands)	Total
<b>Assets (liabilities):</b>				
Money market funds	\$	\$	\$ 1,035	\$ 1,035
Commodity derivative contracts			24,644	24,644
<b>Total</b>	\$	\$	\$ 25,679	\$ 25,679

	<b>Fair value as of December 31, 2010</b>			
	Level 1	Level 2	Level 3 (In thousands)	Total
<b>Assets (liabilities):</b>				
Money market funds	\$	\$	\$ 1,035	\$ 1,035
Commodity derivative contracts			19,657	19,657
<b>Total</b>	\$	\$	\$ 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 counterparties in determining fair value and recorded a downward adjustment to the fair value of its derivative assets in the amount of \$0.6 million at September 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 September 30, 2011 and 2010.

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	<b>Derivatives</b>	<b>Money Market Funds</b>	
	<b>Asset</b>	<b>Asset (Liability)</b>	<b>Total</b>
	<b>(Liability)</b>	<b>(In thousands)</b>	
Balance at January 1, 2011	\$ 19,657	\$ 1,035	\$ 20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	(22,623)		(22,623)
Included in Other Comprehensive Income	24,873		24,873
Purchases, Issuances and Settlements			
Settlements	(8,281)		(8,281)
Purchases	11,018		11,018
Transfers in and out of Level 3			
Balance at September 30, 2011	\$ 24,644	\$ 1,035	\$ 25,679

	<b>Derivatives</b>	<b>Money Market Funds</b>	
	<b>Asset</b>	<b>Asset (Liability)</b>	<b>Total</b>
	<b>(Liability)</b>	<b>(In thousands)</b>	
Balance at January 1, 2010	\$ 6,787	\$ 2,035	\$ 8,822
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)	(1)		(1)
Included in Other Comprehensive Income	51,663		51,663
Purchases, Issuances and Settlements	(18,331)	(2,000)	(20,331)
Transfers in and out of Level 3			
Balance at September 30, 2010	\$ 40,118	\$ 35	\$ 40,153

- (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 September 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 September 30, 2011 was \$250.0 million. The Company calculated the fair value of its long-term debt as of September 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 \$266.0 million at September 30, 2011.

**(6) Asset Retirement Obligations**

The following table provides a roll forward of 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 \$9.0 million and adjustments for obligations that were assumed by the purchasers of divested properties of approximately \$11.2 million. Activity related to the Company's asset retirement obligations (ARO) is as follows:

	<b>Nine Months</b>
	<b>Ended</b>
	<b>September 30, 2011</b>
	<b>(In thousands)</b>
ARO as of December 31, 2010	\$ 27,934
Revision of previous estimates	

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Liabilities incurred during period	18
Liabilities settled during period	(20,216)
Accretion expense	1,005
ARO as of September 30, 2011	\$ 8,741

As of September 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 \$8.6 million and is included in Other long-term liabilities on the Consolidated Balance Sheet.

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*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 significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

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 September 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 September 30, 2011, the Company's current ratio was 3.0 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 September 30, 2011.

The Company's semi-annual borrowing base review was completed on October 14, 2011 and the borrowing base was confirmed by the lenders at \$325.0 million. As of November 1, 2011, the Company had \$30.0 million outstanding, with \$295.0 million available for borrowing under the Restated Revolver.

*Second Lien Term Loan.* The Company's amended and restated term loan (the "Restated Term Loan") matures on October 2, 2012. As of September 30, 2011, the Company had \$20.0 million of fixed rate borrowings outstanding bearing interest 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 September 30, 2011, the Company's reserve coverage ratio was 5.1 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 September 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.



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As of September 30, 2011, the Company had total outstanding borrowings of \$250.0 million and for the nine months ended September 30, 2011, the Company's weighted average borrowing rate was 8.28%.

**(8) Income Taxes**

The effective tax rate for the three and nine months ended September 30, 2011 was 35.8% and 35.0%, respectively, and the effective tax rate for the three and nine months ended September 30, 2010 was 37.6% and 38.1%, respectively. The provision for income taxes for the three months ended September 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 to the impact of state income taxes. For the nine months ended September 30, 2011, the provision for income taxes approximates the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation, state income taxes 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 September 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 statutes of limitation within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2011, the Company has a deferred tax asset of \$101.2 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.

**(9) Commitments and Contingencies**

*Firm Gas Transportation Commitments.* The Company has entered into long-term contracts for firm gas transportation and processing capacity and crude oil transportation to reduce exposure to production constraints in the Eagle Ford shale. Agreements are in place which increase daily gas transportation capacity from the Eagle Ford shale to 195 MMcf/d of gross wellhead production contracted to be available by mid-year 2012 with total contractual capacity of 245 MMcf/d to be available in 2013. Oil transportation commitments provide 5,000 Bbls/d of oil transportation and include selling commitments for five years starting in mid-year 2012. Future obligations under firm gas and oil transportation agreements as of September 30, 2011 are as follows:

	<b>September 30, 2011</b>
	(In thousands)
2011	\$ 906
2012	12,937
2013	40,042
2014	40,042
2015	40,042
After 2015	257,070
	<b>\$ 391,039</b>

*Drilling Rig and Completion Services Commitments.* Drilling rig and completion services commitments represent obligations with certain contractors primarily to execute our Eagle Ford shale and Southern Alberta basin drilling programs. As of September 30, 2011, the Company has

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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

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sufficient to support the current operations. As of September 30, 2011, the minimum remaining contractual commitment for this agreement was \$4.5 million. This minimum commitment will decrease equally on a monthly basis for the remainder of the contract term and payments under the agreement are accounted for as capital additions to our oil and gas properties.

*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. 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**

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In thousands)			
Accumulated other comprehensive (loss) income, beginning of period		\$ (8,751)	\$ 20,123	\$ 4,259
Net income	\$ 31,948	\$ 8,850	\$ 68,345	\$ 20,425
Change in fair value of derivative hedging instruments	\$ 40,706	\$ 18,351	\$ 24,873	\$ 51,663
Hedge settlements reclassified to (income) loss	909	(10,223)	(14,834)	(18,331)
Tax provision related to hedges	(14,914)	(3,077)	(3,348)	(12,417)
Total other comprehensive income	\$ 26,701	\$ 5,051	\$ 6,691	\$ 20,915
Comprehensive income	\$ 58,649	\$ 13,901	\$ 75,036	\$ 41,340
Accumulated other comprehensive income, end of period	\$ 17,950	\$ 25,174	\$ 17,950	\$ 25,174

**(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.

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

	Three Months Ended September 30, 2011		Nine Months Ended September 30, 2010	
	2011	2010	2011	2010
	(In thousands)			
Basic weighted average number of shares outstanding	52,038	51,411	51,962	51,329
Dilution effect of stock option and awards at the end of the period	589	662	631	721
<b>Diluted weighted average number of shares outstanding</b>	<b>52,627</b>	<b>52,073</b>	<b>52,593</b>	<b>52,050</b>
Anti-dilutive stock awards and shares	6	72	3	63

**(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 September 30, 2011		Nine Months Ended September 30, 2010	
	2011	2010	2011	2010
	(in thousands)			
Total stock-based compensation expense	\$ (590)	\$ 3,692	\$ 15,884	\$ 8,317
Capitalized in oil and gas properties	(162)	(141)	(504)	(424)
<b>Net stock-based compensation expense</b>	<b>\$ (752)</b>	<b>\$ 3,551</b>	<b>\$ 15,380</b>	<b>\$ 7,893</b>

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 three and nine months ended September 30, 2011, the Company recorded compensation expense of approximately \$1.2 million and \$4.2 million, respectively, related to these equity awards. As of September 30, 2011, unrecognized stock-based compensation expense related to unvested stock-based compensation equity awards was approximately \$6.4 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 three and nine months ended September 30, 2011, the Company recognized compensation expense of \$(2.9) million and \$9.7 million, respectively, associated with the 2009 PSUs; \$0.6 million and \$1.5 million, respectively, associated with the 2010 PSUs; and \$0.5 million and \$0.5 million, respectively, associated with the 2011 PSUs. The reduction in expense of \$(2.9) million for the three months ended September 30, 2011 associated with the 2009 PSUs was due primarily to the approximate 34% decline in stock price from June 30, 2011 to September 30, 2011.

At the current fair value as of September 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 \$22.0 million, \$8.2 million and \$5.1 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 Elements of Executive Compensation.

**(13) Geographic Area Information**

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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.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011 (1)	2010 (1)	2011 (1)	2010 (1)
	(In thousands)		(In thousands)	
<b>Natural gas, Oil and NGL Revenue</b>				
Eagle Ford	\$ 91,197	\$ 29,327	\$ 243,353	\$ 51,342
South Texas	12,167	17,175	37,959	61,836
California (2)	467	14,521	15,397	53,008
Rockies (2)	151	6,366	3,678	21,379
Gulf Coast	85	580	1,349	6,081
Other Onshore		1,838		6,333
Total revenue, excluding gains on hedges	\$ 104,067	\$ 69,807	\$ 301,736	\$ 199,979

- (1) Excludes the effects of hedging losses of \$2.8 million and hedging gains of \$8.1 million for the three and nine months ended September 30, 2011, respectively, and hedging gains of \$10.5 million and \$19.1 million for the three and nine months ended September 30, 2010, respectively.
- (2) The Rockies and California assets include the DJ Basin and Sacramento Basin assets which 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 September 2011, all employees covered under the programs have been terminated.

A before-tax charge of \$1.5 million (\$1.0 million after-tax) was recorded in the first nine 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 nine months of 2011, approximately \$0.6 million related to severance costs, \$0.7 million related to the cease-use of the Denver office space and approximately \$0.2 million related to relocation costs. Any future costs associated with the restructuring and reorganization of operations are expected to be de minimis. The remaining accrued liability as of September 30, 2011 primarily relates to the Denver office lease.

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During the nine months ended September 30, 2011, the Company made payments of approximately \$3.6 million associated with these liabilities.

	<b>Amounts before tax</b> (In thousands)
Balance at January 1, 2011	\$ 3,224
Accruals	1,191
Adjustments	335
Payments	(3,633)
 Balance at September 30, 2011	 \$ 1,117

**(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.

**(16) Subsequent Events**

On October 14, 2011, the Company's semi-annual borrowing base review was completed and the borrowing base under the Restated Revolver was confirmed at \$325.0 million.

**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") and in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (the "June 2011 Quarterly 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:

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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;

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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;

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 nine months ended September 30, 2011 compared to the three and nine months ended September 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 September 30, 2011 as compared to the same period for 2010:

production on a Bcfe basis increased 7% to 14.2 Bcfe for the three months ended September 30, 2011 from 13.3 Bcfe for the three months ended September 30, 2010;

16 gross (16 net) wells were drilled with a net success rate of 100% for the three months ended September 30, 2011 compared to 22 gross (22 net) wells drilled with a net success rate of 95% for the same period in 2010;

67% of revenue for the three months ended September 30, 2011 was generated from oil and NGL sales as compared to 33% for the same period in 2010, reflecting our shift to a higher total liquids mix;

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average realized gas prices, including hedging, decreased \$0.58 per Mcf, or 11%, to \$4.75 per Mcf for the three months ended September 30, 2011 from \$5.33 per Mcf for the three months ended September 30, 2010;

average realized oil prices, including hedging, increased \$1.44 per Bbl, or 2%, to \$70.53 per Bbl for the three months ended September 30, 2011 from \$69.09 per Bbl for the three months ended September 30, 2010;

average realized NGL prices, including hedging, increased \$12.10 per Bbl, or 33%, to \$48.75 per Bbl for the three months ended September 30, 2011 from \$36.65 per Bbl for the three months ended September 30, 2010;

total revenue, including the effects of hedging, increased \$21.0 million, or 26%, to \$101.3 million for the three months ended September 30, 2011 from \$80.3 million for the three months ended September 30, 2010; and

diluted earnings per share increased \$0.44 to \$0.61 for the three months ended September 30, 2011 from \$0.17 for the three months ended September 30, 2010.

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

production on a Bcfe basis increased 17% to 42.8 Bcfe for the nine months ended September 30, 2011 from 36.7 Bcfe for the nine months ended September 30, 2010;

40 gross (39 net) wells were drilled with a net success rate of 100% for the nine months ended September 30, 2011 compared to 116 gross (114 net) wells drilled with a net success rate of 98% for the same period in 2010;

58% of revenue for the nine months ended September 30, 2011 was generated from oil and NGL sales as compared to 28% for the same period in 2010, reflecting our shift to a higher total liquids mix;

average realized gas prices, including hedging, increased \$0.04 per Mcf, or 1%, to \$5.33 per Mcf for the nine months ended September 30, 2011 from \$5.29 per Mcf for the nine months ended September 30, 2010;

average realized oil prices, including hedging, increased \$6.04 per Bbl, or 8%, to \$77.88 per Bbl for the nine months ended September 30, 2011 from \$71.84 per Bbl for the nine months ended September 30, 2010;

average realized NGL prices, including hedging, increased \$6.03 per Bbl, or 15%, to \$46.21 per Bbl for the nine months ended September 30, 2011 from \$40.18 per Bbl for the nine months ended September 30, 2010;

total revenue, including the effects of hedging, increased \$90.9 million, or 41%, to \$309.9 million for the nine months ended September 30, 2011 from \$219.0 million for the nine months ended September 30, 2010; and

diluted earnings per share increased \$0.91 to \$1.30 for the nine months ended September 30, 2011 from \$0.39 for the nine months ended September 30, 2010.

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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 a conventional natural gas producer in more mature U.S. basins to that of an operator in emerging U.S. shale plays. The change in strategy has resulted in a more balanced commodity mix, greater returns and drilling 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 have exceeded previous expectations. The Eagle Ford shale has become our largest producing area providing approximately 85% of our total production for the third quarter of 2011. In addition, approximately 56% of production from the Eagle Ford shale for the current quarter was from crude oil and NGLs.

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 that was completed during the second quarter of 2011. 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. During the third quarter of 2011, we drilled three of the seven planned horizontal wells and drilling on the fourth horizontal well is nearly complete. Drilling operations will begin on the remaining three wells in the seven-well horizontal program during the first quarter of 2012. 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.

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At June 30, 2011, we provided a mid-year update to our proved reserves due to continued well performance significantly in excess of prior estimates. In our update, we estimated 969.8 Bcfe of proved reserves, of which 29% was proved developed at that time. These proved reserves represent an increase of 102% from proved reserves of 479.3 Bcfe at December 31, 2010. This increase resulted primarily from additional 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 within five years from the date recorded as a proved undeveloped reserve.

The overall metrics of our business have been greatly improved with our success in the Eagle Ford shale. Our average revenue increased by \$1.09 per Mcfe in the third quarter of 2011 compared to the same period in 2010 primarily due to significant growth in higher-valued oil and NGL production. For the current quarter, approximately 51% of our overall production mix was attributable to oil and NGL production compared to 24% a year ago. Our cost control effectiveness and divesting of certain assets has also led to a decrease in lease operating expense which declined to \$0.31 per Mcfe in the current quarter of 2011 from \$0.86 per Mcfe for the same period in 2010.

With the growth of our shale activities, we have streamlined our operations by divesting of assets that no longer fit our operating model and redeploying the proceeds of the sales into our growth initiatives. In total, we have executed sale agreements for more than \$340 million for properties in nine states. During 2011, we divested 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. We closed on the sale of our DJ Basin assets on March 31, 2011 and through multiple stages, closed on the sale of our Sacramento Basin assets through the third quarter of 2011. Both of these asset divestitures are effective as of 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.

At mid-year, 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 the third quarter, we began testing our acreage position outside Gates Ranch located in the liquids portion of the Eagle Ford shale and drilled three discovery wells. In the Southern Alberta Basin, we are currently drilling horizontal wells that are part of the second phase of our delineation initiative. In total, approximately 85 percent of capital spending for the year 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.

In the third quarter of 2011, we were operating three rigs in the Eagle Ford shale while completing 12 horizontal wells. As of September 30, 2011, we have completed a total of 52 horizontal wells in this play. In addition, we successfully initiated infill drilling in two pilot areas within Gates Ranch. The wells drilled in both pilot areas should be completed and on production by year-end 2011. Based on continued reservoir analysis, we adjusted optimum well spacing to between 60 and 80 acres for our Eagle Ford development areas. Through these assumptions, we have identified roughly 800 Eagle Ford drilling locations. At a targeted pace of approximately 60 completions per year, we expect to develop our current Eagle Ford inventory over the next 10 to 15 years.

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 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. We have agreements in place which increase daily transportation capacity from the Eagle Ford shale to 195 MMcf/d of gross wellhead production contracted to be available by mid-year 2012 with total contractual capacity of 245 MMcf/d to be available in 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 any future costs associated with the restructuring and reorganization of operations are expected to be de minimis. The consolidation of our technical resources to Houston is allowing us to capitalize on the dynamics and efficiencies of operating in a central location.



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

In April 2011, we used \$100.0 million of the proceeds from our asset divestitures to reduce our outstanding debt under our Amended and Restated Senior Revolving Credit Agreement (the "Restated Revolver"). 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. Our semi-annual borrowing base redetermination was completed in October 2011 and our borrowing base under the Restated Revolver was reconfirmed by our lenders at \$325.0 million. Our positive performance and results of operations offset by our divestiture activities could have allowed for an increase in the borrowing base. However, we did not request an increase to the borrowing base at this time. As of November 1, 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 September 30, 2011 was \$101.3 million, which is an increase of \$21.0 million, or 26%, from \$80.3 million for the three months ended September 30, 2010. Total revenue, excluding the effects of hedging, for the three months ended September 30, 2011 was \$104.1 million, which is an increase of \$34.3 million, or 49%, from \$69.8 million for the three months ended September 30, 2010. Approximately 67% of our revenue for the three months ended September 30, 2011 was attributable to oil and NGL sales as compared to 33% for the same period in 2010.

Total revenue, including the effects of hedging, for the nine months ended September 30, 2011 was \$309.9 million, which is an increase of \$90.9 million, or 41%, from \$219.0 million for the nine months ended September 30, 2010. Total revenue, excluding the effects of hedging, for the nine months ended September 30, 2011 was \$301.7 million, which is an increase of \$101.7 million, or 51%, from \$200.0 million for the nine months ended September 30, 2010. Approximately 58% of our revenue for the nine months ended September 30, 2011 was attributable to oil and NGL sales as compared to 28% for the same period in 2010.

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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 September 30,			Nine Months Ended September 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)		
<b>Revenues:</b>						
Natural gas sales	\$ 33,256	\$ 53,783	(38%)	\$ 129,493	\$ 157,081	(18%)
Oil sales	31,590	15,406	105%	94,651	33,162	185%
NGL sales	36,411	11,078	229%	85,741	28,794	198%
<b>Total revenue</b>	<b>\$ 101,257</b>	<b>\$ 80,267</b>	<b>26%</b>	<b>\$ 309,885</b>	<b>\$ 219,037</b>	<b>41%</b>
<b>Production:</b>						
Gas (Bcf)	7.0	10.1	(31%)	24.3	29.7	(18%)
Oil (MBbls)	447.9	223.0	101%	1,215.4	461.6	163%
NGLs (MBbls)	746.9	302.3	147%	1,855.4	716.6	159%
Total Equivalents (Bcfe)	14.2	13.3	7%	42.8	36.7	17%
<b>\$ per unit:</b>						
Avg. natural gas price per Mcf, excluding hedging	\$ 4.40	\$ 4.29	3%	\$ 4.35	\$ 4.65	(6%)
Avg. natural gas price per Mcf	4.75	5.33	(11%)	5.33	5.29	1%
Avg. oil price per Bbl, excluding hedging	75.18	69.09	9%	84.72	71.84	18%
Avg. oil price per Bbl	70.53	69.09	2%	77.88	71.84	8%
Avg. NGL price per Bbl, excluding hedging	53.00	36.65	45%	50.20	40.18	25%
Avg. NGL price per Bbl	48.75	36.65	33%	46.21	40.18	15%
Avg. revenue per Mcfe	7.13	6.04	18%	7.24	5.97	21%

**Natural Gas.** For the three and nine months ended September 30, 2011, natural gas revenue, including the effects of hedging, decreased by \$20.5 million and \$27.6 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, decreased by \$0.58 per Mcf for the three months ended September 30, 2011 and increased by \$0.04 per Mcf for the nine months ended September 30, 2011 from the same period in 2010, respectively. The effect of natural gas hedging activities on natural gas revenue for the three months ended September 30, 2011 resulted in a gain of \$2.5 million as compared to a gain of \$10.5 million for the three months ended September 30, 2010. The effect of natural gas hedging activities on natural gas revenue for the nine months ended September 30, 2011 resulted in a gain of \$23.9 million as compared to a gain of \$19.1 million for the nine months ended September 30, 2010.

**Crude Oil.** For the three and nine months ended September 30, 2011, oil revenue, including the effects of hedging, increased by \$16.2 million and \$61.5 million, respectively, from the same periods in 2010. The increase in both periods was attributable to an increase in production of 224.9 MBbls and 753.8 MBbls, respectively, for the three and nine months ended September 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 \$1.44 per Bbl and \$6.04 per Bbl, respectively, for the three and nine months ended September 30, 2011 from the same periods in 2010. The effect of oil hedging activities on oil revenue for the three and nine months ended September 30, 2011 resulted in losses of \$2.1 million and \$8.3 million, respectively. There was no effect of oil hedging activities on oil revenue for either the three or nine months ended September 30, 2010 as no oil derivative transactions settled during the those periods.

**NGLs.** For the three and nine months ended September 30, 2011, NGL revenue, including the effects of hedging, increased by \$25.3 million and \$56.9 million, respectively, from the same periods in 2010. The increase in both periods was attributable to an increase in production of 444.6 MBbls and 1,138.8 MBbls, respectively, for the three and nine months ended September 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 \$12.10 per Bbl and \$6.03 per Bbl, respectively, for the three and nine months ended September 30, 2011 from the same periods in 2010. The effect of NGL hedging activities on NGL revenue for the three and nine months ended September 30, 2011 resulted in losses of \$3.2 million and \$7.4 million, respectively. There was no effect of NGL hedging activities on NGL revenue for either the three or nine months ended September 30, 2010 as no NGL derivative transactions settled during the those periods.



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The following table presents information regarding our operating expenses:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	% Change Increase/ (Decrease)	2011	2010	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)					
Lease operating expense	\$ 4,445	\$ 11,486	(61%)	\$ 27,975	\$ 39,473	(29%)
Depreciation, depletion and amortization	24,657	32,163	(23%)	92,041	81,696	13%
Treating, transportation and marketing	5,481	1,878	192%	13,807	4,765	190%
Production taxes	2,107	1,565	35%	6,736	4,940	36%
General and administrative costs	9,453	12,560	(25%)	46,830	35,693	31%
<b>\$ per unit:</b>						
Avg. lease operating expense per Mcfe	\$ 0.31	\$ 0.86	(64%)	\$ 0.65	\$ 1.08	(40%)
Avg. DD&A per Mcfe	1.74	2.42	(28%)	2.15	2.23	(4%)
Avg. treating, transportation and marketing per Mcfe	0.39	0.14	179%	0.32	0.13	146%
Avg. production taxes per Mcfe	0.15	0.12	25%	0.16	0.13	23%
Avg. production costs per Mcfe (1)	2.05	3.28	(38%)	2.80	3.30	(15%)
Avg. production costs per Mcfe, excluding taxes (2)	2.08	3.21	(35%)	2.69	3.11	(14%)
Avg. General and administrative costs per Mcfe	0.67	0.94	(29%)	1.09	0.97	12%
Avg. General and administrative costs per Mcfe, excluding stock-based compensation	0.72	0.68	6%	0.73	0.76	(4%)

(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 nine months ended September 30, 2011, lease operating expense decreased \$7.0 million and \$11.5 million, respectively, compared to the same periods in 2010. The decrease was primarily attributable to the divestiture of properties which contributed to a decline in direct lease operating expense of \$6.1 million and \$13.2 million, respectively, and a decline in ad valorem taxes of \$1.0 million and \$3.2 million, respectively, for the three and nine months ended September 30, 2011 compared to 2010. The decrease for the nine months ended September 30, 2011 was partially offset by an increase in direct lease operating expense of \$5.1 million related to our Eagle Ford operations.

**Depreciation, Depletion and Amortization.** For the three and nine months ended September 30, 2011, DD&A expense decreased \$7.5 million and increased \$10.3 million, respectively, from the same periods in 2010. The decrease for the three months ended September 30, 2011 was due primarily to the upward revision in proved reserves as of June 30, 2011 and the divestiture of the Sacramento Basin properties. The increase for the nine months ended September 30, 2011 was due primarily to increased production partially offset by a lower DD&A rate resulting from the second quarter reserves revision.

**Treating, Transportation and Marketing.** Treating, transportation and marketing expense increased \$3.6 million and \$9.0 million, respectively, for the three and nine months ended September 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 transportation capacity is in high demand.

**Production Taxes.** Production taxes as a percentage of unhedged natural gas, oil and NGL sales were 2.0% and 2.2%, respectively, for the three and nine months ended September 30, 2011 as compared to 2.2% and 2.5%, respectively, for the same periods in 2010. The decrease in rate was primarily due to production tax credits in the State of Texas.

**General and Administrative Costs.** General and administrative costs decreased \$3.1 million for the three months ended September 30, 2011 from the same period in 2010. The decrease was primarily due to a \$4.3 million decrease in stock-based compensation expense related to the 34% decline in stock price from June 30, 2011 to September 30, 2011 and a \$0.9 million decrease in salaries, wages, benefits and bonuses due to lower head count. The decrease was offset by a decline in billable overhead and capitalizable costs of \$1.1 million, an increase of \$0.5 million in contractor expenses and increase of \$0.5 million in other general and administrative expenses.

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General and administrative costs increased \$11.1 million for the nine months ended September 30, 2011 from the same period in 2010. The increase was primarily due to a \$7.5 million increase in stock-based compensation expense related to the 46% increase in stock price from September 30, 2010 to September 30, 2011, a \$2.8 million increase in contractor expenses, a decline in billable overhead and capitalizable costs of \$2.3 million and an increase of \$0.2 million in other general and administrative expenses. The increase was offset by a decrease of \$1.7 million in salaries, wages, benefits and bonuses due to lower head count.

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**Total Other Expense**

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other income/expense, net, decreased \$1.1 million and \$2.1 million, respectively, for the three and nine months ended September 30, 2011 from the same periods in 2010.

For the three and nine months ended September 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 nine months ended September 30, 2011 was 8.95% and 8.28%, respectively, compared to 7.39% and 7.01%, 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 nine months ended September 30, 2011 was 35.8% and 35.0%, respectively, and the effective tax rate for the three and nine months ended September 30, 2010 was 37.6% and 38.1%, respectively. The provision for income taxes for the three months ended September 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 to the impact of state income taxes. For the nine months ended September 30, 2011, the provision for income taxes approximates the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation, state income taxes 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 September 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 September 30, 2011, we have a deferred tax asset of \$101.2 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.

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**Table of Contents****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 natural gas, oil and NGLs 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 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. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

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 September 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 September 30, 2011, our current ratio was 3.0 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 September 30, 2011.

Our semi-annual borrowing base review was completed on October 14, 2011 and the borrowing base was confirmed by our lenders at \$325.0 million.

*Second Lien Term Loan.* Our amended and restated term loan (the Restated Term Loan ) matures on October 2, 2012. As of September 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 September 30, 2011, our reserve coverage ratio was 5.1 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 September 30, 2011.



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*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.

**Cash Flows**

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

	<b>Nine Months Ended September 30,</b>	
	<b>2011</b>	<b>2010</b>
	(In thousands)	
Cash flows provided by operating activities	\$ 201,770	\$ 133,551
Cash flows (used in) investing activities	(31,150)	(234,044)
Cash flows (used in) provided by financing activities	(105,386)	63,479
Net increase/(decrease) in cash and cash equivalents	\$ 65,234	\$ (37,014)

*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 \$68.2 million for the nine months ended September 30, 2011 as compared to the same period for 2010. Cash flows for 2011 increased primarily due to higher oil and NGL prices, higher production volumes and the impact of changes in working capital but were partially offset by lower natural gas prices and lower natural gas production volumes.

*Investing Activities.* The primary drivers of cash used in investing activities are capital spending and sales proceeds from asset divestitures.

Cash flows used in investing activities decreased by \$202.9 million for the nine months ended September 30, 2011 as compared to the same period for 2010. The net decrease 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 40 gross wells as compared to the drilling of 116 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 \$168.9 million for the nine months ended September 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 nine months ended September 30, 2011 while financing activities in the nine months ended September 30, 2010 resulted in net repayments of \$130.0 million under the Restated Term Loan and Restated Revolver and the \$200.0 million issuance of the Senior Notes.

**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.

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Our capital expenditures for the nine months ended September 30, 2011 increased by \$87.3 million to \$339.0 million, from \$251.7 million compared to the same period in 2010. During the nine months ended September 30, 2011, we participated in the drilling of 40 gross wells with the majority of these being in the Eagle Ford shale. At current commodity prices, our positive operating

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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 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 the 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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
<b>Natural Gas</b>				
Quantity settled (MMBtu)	4,600,000	5,060,000	13,650,000	9,585,000
Increase in natural gas sales revenue (In thousands) (1)	\$ 2,450	\$ 10,460	\$ 12,854	\$ 19,058
<b>Crude Oil</b>				
Quantity settled (Bbl)	312,800		647,000	
Decrease in crude oil sales revenue (In thousands) (2)	\$ (181)	\$	\$ (1,635)	\$
<b>NGL</b>				
Quantity settled (Bbl)	184,000		429,000	
Decrease in NGL sales revenue (In thousands)	\$ (3,178)	\$	\$ (7,403)	\$
<b>Interest Rate Swaps</b>				
(Increase) in interest expense (In thousands)	\$	\$ (237)	\$	\$ (727)

(1) For the nine months ended September 30, 2011, excludes approximately \$11.1 million 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.

(2) For the three and nine months ended September 30, 2011, excludes approximately \$1.9 million and \$6.7 million, respectively, 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. 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. We assess the effectiveness of these hedging transactions on a quarterly basis, consistent with the 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).

Derivative instruments that do not qualify as cash flow hedges are also recorded on the balance sheet at their fair market value each period but with the change in fair value representing unrealized gains and losses recognized immediately in earnings. 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.

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As of September 30, 2011, our commodity hedge and non-qualifying derivative positions were with counterparties that were also lenders under our credit facilities. This allows us to satisfy any need for 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 September 30, 2011, we had no deposits for collateral in regard to our commodity hedge positions.

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### **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 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<sub>2</sub>e) 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 for our facilities that emit more than 25,000 tons per year of CO<sub>2</sub>e, and in 2012 for certain of our other facilities. 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<sub>2</sub>e. This rule does not currently affect our operations but may as our operations grow. Finally, the EPA is considering additional rulemaking to apply these permitting requirements to broader classes of emission sources, such as facilities with CO<sub>2</sub>e 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 federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. The Secretary of Energy Advisory Board published their ninety-day report that included a number of recommendations. The results of the other studies are expected by the end of 2012. The EPA is developing permitting guidance under the SDWA for hydraulic fracturing activities that use diesel fuels in fracturing fluids. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate waste water discharges from hydraulic fracturing and other natural gas production. 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. In June 2011, Texas adopted legislation (HB 3328), and in September 2011 the Texas Railroad Commission proposed new regulations implementing this statute, which will become effective in July 2012 if adopted as proposed. Under HB 3328 exploration and production operators in Texas will be required to publicly disclose the chemicals used in hydraulic fracturing. Additionally, on September 15, 2011, the Montana Board of Oil and Gas Conservation adopted rules that would require the public disclosure of fracturing fluid constituents. Because we already participate in public disclosure on the FracFocus.com internet site we do not anticipate experiencing a material adverse effect from such disclosure requirements. The outcome for other proposed state, regional and local regulations is uncertain, but potential 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.

*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 derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission to promulgate rules and regulations implementing the 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 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

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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.

### **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 as applicable. 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.

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### **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 September 30, 2011, based on a Henry Hub gas price of \$4.16 per MMBtu and a West Texas Intermediate oil price of \$91.00 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 September 30, 2011. It is possible that a write-down of our oil and gas properties could occur in the future should natural gas, oil and NGL 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 September 30, 2011, approximately 100% of total hedged natural gas transactions represented hedged prices of natural gas at the Houston Ship Channel, 63% of hedged crude oil transactions represented hedged prices of crude oil at the West Texas Intermediate on the NYMEX, with the remaining 37% 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 September 30, 2011, we had open natural gas derivative hedges in an asset position with a fair value of \$16.8 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately \$3.7 million, while a 10 percent decrease in natural gas prices would increase the fair value by approximately \$3.8 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 September 30, 2011, we had open crude oil derivative hedges in an asset position with a fair value of \$15.6 million. A 10 percent increase in crude oil prices would reduce the fair value by approximately \$12.0 million, while a 10 percent decrease in crude oil prices would increase the fair value by approximately \$11.7 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**.



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As of September 30, 2011, we had open NGL derivative hedges in a liability position with a fair value of \$7.7 million. A 10 percent increase in NGL prices would reduce the fair value by approximately \$6.5 million, while a 10 percent decrease in NGL prices would increase the fair value by approximately \$6.5 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 September 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 September 30, 2011, we had no deposits for collateral in regard 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 September 30, 2011. We evaluated non-performance risk using the current credit default swap values and default probabilities for the counterparties and recorded a downward adjustment to the fair value of our derivative assets in the amount of \$0.6 million at September 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 September 30, 2011. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of September 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.

There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our 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 as applicable. 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.

#### **Item 1A. Risk Factors**

There have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2010 Annual Report and our June 2011 Quarterly Report.

**Table of Contents****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 September 30, 2011:*

<b>Period</b>	<b>Total Number of Shares Purchased (1)</b>	<b>Average Price Paid per Share</b>	<b>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</b>	<b>Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs</b>
July 1 July 31	2,358	\$ 51.62		
August 1 August 31	435	53.50		
September 1 September 30	1,688	43.93		
Total	4,481	\$ 48.91		

- (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**

None.

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**Item 6. Exhibits**

<b>Exhibit Number</b>	<b>Description</b>
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

\* Filed herewith

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**SIGNATURES**

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

ROSETTA RESOURCES INC.

By: /s/ MICHAEL J. ROSINSKI  
Michael J. Rosinski  
*Executive Vice President, Chief Financial Officer and Treasurer*  
(Duly Authorized Officer and Principal Financial Officer)

Date: November 7, 2011

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**ROSETTA RESOURCES INC.**

**EXHIBIT INDEX**

<b>Exhibit Number</b>	<b>Description</b>
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

\* Filed herewith