Rosetta Resources Inc.
Form 10-Q
November 05, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934

For The Quarterly Period Ended September 30, 2010

OR

o Transition Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission File Number: 000-51801

ROSETTA RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	43-2083519 (I.R.S. Employer Identification No.)
717 Texas, Suite 2800, Houston, TX (Address of principal executive offices)	77002 (Zip Code)

(Registrant's telephone number, including area code) (713) 335-4000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See 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 o	Accelerated filer x
Non-Accelerated filer o (Do not check if smaller reporting company)	Smaller Reporting Company o

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

The number of shares of the registrant's Common Stock, $.001 par value per share, outstanding as of November 3, 2010 was 52,696,265.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

Rosetta Resources Inc.
Consolidated Balance Sheet
(In thousands, except par value and share amounts)

	September 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$24,242	$61,256
Accounts receivable, net	30,025	32,691
Derivative instruments	31,446	8,983
Prepaid expenses	3,630	2,837
Other current assets	5,791	6,415
Total current assets	95,134	112,182
Oil and natural gas properties, full cost method, of which $80,912 at September 30, 2010 and $42,344 at December 31, 2009 were excluded from amortization	2,248,687	2,011,972
Other fixed assets	14,393	12,417
	2,263,080	2,024,389
Accumulated depreciation, depletion, and amortization, including impairment	(1,513,787)	(1,433,787)
Total property and equipment, net	749,293	590,602
Deferred loan fees	8,202	4,921
Deferred tax asset	153,470	169,732
Derivative instruments	8,820	-
Other assets	2,443	2,147
Total other assets	172,935	176,800
Total assets	$1,017,362	$879,584
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$1,446	$2,279
Accrued liabilities	60,907	37,107
Royalties payable	11,878	16,064
Derivative instruments	148	236
Prepayment on gas sales	7,045	7,542
Deferred income taxes	11,694	3,258
Total current liabilities	93,118	66,486
Long-term liabilities:		
Derivative instruments	-	1,960
Long-term debt	360,000	288,742
Other long-term liabilities	24,564	29,301
Total liabilities	477,682	386,489
Commitments and Contingencies (Note 9)		

Stockholders' equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2010 or 2009	-	-
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 51,718,416 shares and 51,254,709 shares at September 30, 2010 and December 31, 2009, respectively	51	51
Additional paid-in capital	787,520	780,196
Treasury stock, at cost; 298,345 and 199,955 shares at September 30, 2010 and December 31, 2009, respectively	(5,552)	(3,473)
Accumulated other comprehensive income	25,174	4,259
Accumulated deficit	(267,513)	(287,938)
Total stockholders' equity	539,680	493,095
Total liabilities and stockholders' equity	$1,017,362	$879,584

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

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenues:				
Natural gas sales	$53,783	$54,207	$157,081	$187,238
Oil sales	15,406	4,435	33,162	16,116
NGL sales	11,078	5,842	28,794	14,122
Total revenues	80,267	64,484	219,037	217,476
Operating costs and expenses:				
Lease operating expense	11,486	13,312	39,473	47,921
Depreciation, depletion, and amortization	32,163	23,029	81,696	95,928
Impairment of oil and gas properties	-	-	-	379,462
Treating, transportation and marketing	1,878	1,832	4,765	5,193
Production taxes	1,565	1,109	4,940	4,183
General and administrative costs	12,560	10,414	35,693	32,358
Total operating costs and expenses	59,652	49,696	166,567	565,045
Operating income (loss)	20,615	14,788	52,470	(347,569)
Other (income) expense:				
Interest expense, net of interest capitalized	6,575	5,239	20,367	13,880
Interest (income)	-	(16)	(29)	(93)
Other (income) expense, net	(149)	(11)	(883)	149
Total other expense	6,426	5,212	19,455	13,936
Income (loss) before provision for income taxes	14,189	9,576	33,015	(361,505)
Income tax expense (benefit)	5,339	3,845	12,590	(133,138)
Net income (loss)	$8,850	$5,731	$20,425	$(228,367)
Earnings (loss) per share:				
Basic	$0.17	$0.11	$0.40	$(4.48)
Diluted	$0.17	$0.11	$0.39	$(4.48)
Weighted average shares outstanding:				
Basic	51,411	50,994	51,329	50,961
Diluted	52,073	51,291	52,050	50,961

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

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

	Nine Months Ended September 30, 2010	2009
Cash flows from operating activities		
Net income (loss)	$20,425	$(228,367)
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	81,696	95,928
Impairment of oil and gas properties	-	379,462
Deferred income taxes	12,282	(131,056)
Amortization of deferred loan fees recorded as interest expense	2,222	1,621
Amortization of original issue discount recorded as interest expense	1,258	228
Stock compensation expense	7,894	4,951
Change in operating assets and liabilities:		
Accounts receivable	2,666	22,939
Prepaid expenses	(68)	1,230
Other current assets	624	(1,211)
Other assets	(296)	(444)
Accounts payable	(833)	(222)
Accrued liabilities	10,364	(5,546)
Royalties payable	(4,683)	(16,589)
Net cash provided by operating activities	133,551	122,924
Cash flows from investing activities		
Acquisition of oil and gas properties	(5,850)	(3,721)
Additions of oil and gas assets	(243,066)	(99,191)
Disposals of oil and gas properties and assets	14,872	19,483
Decrease in restricted cash	-	1,421
Net cash used in investing activities	(234,044)	(82,008)
Cash flows from financing activities		
(Payments on)/borrowings on Restated Term Loan	(80,000)	23,400
Borrowings on Restated Revolver	64,000	5,000
Payments on Restated Revolver	(114,000)	(40,000)
Issuance of Senior Notes	200,000	-
Deferred loan fees	(6,228)	(5,855)
Proceeds from stock options exercised	1,786	-
Purchases of treasury stock	(2,079)	(618)
Net cash provided by (used in) financing activities	63,479	(18,073)
Net (decrease) increase in cash	(37,014)	22,843
Cash and cash equivalents, beginning of period	61,256	42,855
Cash and cash equivalents, end of period	$24,242	$65,698
Supplemental disclosures:		
Capital expenditures included in accrued liabilities	$20,461	$9,489

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. The Company's operations are concentrated in the core areas of South Texas, including the Eagle Ford shale, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in northwest Montana. Additionally, the Company has non-core, non-operated positions in shallow waters of the Gulf of Mexico.

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, 2009 ("2009 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 (loss).

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2009 Annual Report.

Principles of Consolidation. The accompanying consolidated financial statements as of September 30, 2010 and December 31, 2009 and for the three and nine months ended September 30, 2010 and 2009 contain the accounts of Rosetta Resources Inc. and its wholly owned subsidiaries after eliminating all significant intercompany balances and transactions.

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 must be presented separately. These disclosures are 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 are effective on January 1, 2011. The application of this guidance for the period ended September 30, 2010 for Level 1 and Level 2 fair value measurements did not have an impact on the Company's fair value disclosures or the consolidated financial position, results of operations or cash flows. The guidance for Level 3 fair value measurements will require additional disclosures in future periods but is not expected to impact the Company's consolidated financial position, results of operations or cash flows.

Subsequent Events. In May 2009, the FASB issued authoritative guidance on subsequent events to incorporate accounting guidance that originated as auditing standards into the body of authoritative literature issued by the FASB. This guidance requires the evaluation of subsequent events through the date the financial statements are issued or are available for issue and the disclosure of the date through which subsequent events were evaluated and the basis for that date. This guidance is effective for interim and annual financial periods ending after June 15, 2009. The Company adopted the requirements of this guidance for the period ended June 30, 2009 and the adoption did not have a significant impact on the Company's consolidated financial position, results of operations or cash flows. On February 25, 2010, the FASB amended this guidance to remove the requirement to disclose the date through which an entity has evaluated subsequent events.

Variable Interest Entities. In June 2009, the FASB issued authoritative guidance related to variable interest entities which changes how a reporting entity determines when an entity is insufficiently capitalized or not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities is effective on January 1, 2010. The Company applied this guidance for the period ended September 30, 2010 and it did not have an impact on the Company's consolidated financial position, results of operations or cash flows.

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(3) Property and Equipment

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

	September 30, 2010	December 31, 2009
	(In thousands)	
Proved properties	$2,117,184	$1,931,054
Unproved/unevaluated properties	80,912	42,344
Gas gathering system and compressor stations	50,591	38,574
Other fixed assets	14,393	12,417
Total property and equipment, gross	2,263,080	2,024,389
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,513,787)	(1,433,787)
Total property and equipment, net	$749,293	$590,602

On March 12, 2010, the Company purchased a non-producing leasehold in the South Texas Gates Ranch area for $11.3 million. The purchase was effective as of March 1, 2010. On March 26, 2010, the Company further increased its working interest from 70% to 100% in certain properties in the South Texas Gates Ranch area for $12.5 million. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments.

On April 8, 2010, the Company purchased the remaining 30% working interest and obtained operatorship in the Catarina Field for $5.9 million from St. Mary Land & Exploration Company. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments. On April 13, 2010, the Company divested its Gulf Coast Texas State Waters Sabine Lake asset, a non-core property, for $10.2 million. The proceeds were recorded as an adjustment to the full cost pool with no gain or loss recognized. Also during the second quarter of 2010, the Company purchased an additional 315 acres and 5,000 acres in the Eagle Ford and Bakken plays, respectively, for approximately $946,000 and $200,000, respectively.

On July 28, 2010, the Company leased an additional 3,000 acres for $8.9 million in the Eagle Ford play in South Texas. As of September 30, 2010, the Company’s acreage within the Eagle Ford play was approximately 65,000 acres. On August 27, 2010, the Company entered into a purchase and sale agreement for $37.1 million to divest certain non-core properties located in Arkansas, Texas and Louisiana. The divestiture of these assets, collectively known as the Arklatex assets, closed on October 19, 2010 with an effective date of August 1, 2010 and was subject to post-closing purchase price adjustments.

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $2.3 million and $1.3 million of internal costs for the three months ended September 30, 2010 and 2009, respectively, and $6.2 million and $3.1 million for the nine months ended September 30, 2010 and 2009, respectively.

Included in the Company’s oil and gas properties are asset retirement costs of $20.9 million and $21.9 million as of September 30, 2010 and December 31, 2009, respectively.

Oil and gas properties include costs of $80.9 million and $42.3 million as of September 30, 2010 and December 31, 2009, 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, 2009 to September 30, 2010 is a result of leasehold acquisitions and the costs associated with unevaluated wells in the Rockies and Eagle Ford play.

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, 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 exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded at September 30, 2010. It is possible that a write-down of the Company's oil and gas properties could occur in the future should 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 2009, the Company’s ceiling test was calculated using hedge adjusted market prices of gas and oil at September 30, 2009, which were based on a Henry Hub price of $3.30 per MMBtu and a West Texas Intermediate oil price of $67.00 per Bbl (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at September 30, 2009 increased the calculated ceiling value by approximately $50.7 million (pre-tax). The use of these prices would have resulted in a pre-tax write-down of $18.8 million at September 30, 2009. As allowed under the full cost accounting rules in effect at that time, the Company re-evaluated its ceiling test on October 29, 2009 using the market price for Henry Hub of $4.59 per MMBtu and West Texas Intermediate of $76.25 per Bbl (adjusted for basis and quality differentials). At these prices, cash flow hedges of natural gas production in place increased the calculated ceiling value by approximately $29.3 million (pre-tax). 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 for the quarter ended September 30, 2009.

Also in 2009, the Company’s ceiling test was calculated using hedge adjusted market prices of gas and oil at March 31, 2009, which were based on a Henry Hub price of $3.63 per MMBtu and a West Texas Intermediate oil price of $46.00 per Bbl (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at March 31 increased the calculated ceiling value by approximately $79.7 million (pre-tax). Based upon the analysis, a non-cash, pre-tax write-down of $379.5 million was recorded at March 31, 2009.

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(4) Commodity Hedging Contracts and Other Derivatives

The following commodity fixed price 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 at September 30, 2010:

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	2010	Swap	Cash flow	25,000	2,300,000	$ 6.83	$ -	$ 6,862
Natural gas	2010	Costless Collar	Cash flow	30,000	2,760,000	5.75	7.12	4,553
Natural gas	2011	Swap	Cash flow	15,000	5,475,000	5.85	-	9,322
Natural gas	2011	Costless Collar	Cash flow	35,000	12,775,000	5.79	7.27	18,136
Natural gas	2012	Costless Collar	Cash flow	10,000	3,660,000	5.75	7.15	3,712
					26,970,000			$ 42,585

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	800	292,000	$ 70.00	$ 90.05	$ (868)

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 (1)	2011	Swap	Cash flow	700	255,500	$ 51.74	$ -	$ (1,354)

(1) Hedging arrangement includes propane, butane, isobutane, and pentane and excludes the ethane component of the NGL barrel.

The Company has hedged the interest rates on $100.0 million of its outstanding debt through December 31, 2010. As of September 30, 2010, the Company had the following financial interest rate swap position outstanding:

Settlement Period	Derivative Instrument	Hedge Strategy	Average Fixed Rate	Fair Market Value Asset/(Liability)

				(In thousands)
October 1 - December 31, 2010	Swap	Cash Flow	1.24 %	$ (245)

The Company’s current cash flow hedge positions are with counterparties that are also lenders under the Company’s credit facilities. This 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 the Company’s hedge related credit obligations. As of September 30, 2010, the Company had made no deposits for collateral.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Natural Gas	2010	2009	2010	2009
Quantity settled (MMBtu)	5,060,000	5,256,972	9,585,000	15,599,493
Increase in natural gas sales revenue (In thousands)	$10,460	$22,918	$19,058	$60,077
Interest Rate Swaps				
(Increase) in interest expense (In thousands)	$(237)	$-	$(727)	$(1,034)

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As of September 30, 2010, the Company expects to reclassify net gains of $31.3 million to earnings from the balance in Accumulated other comprehensive income on the Consolidated Balance Sheet during the next twelve months based on current forward prices as of September 30, 2010.

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed through derivative instruments are commodity price risk and interest rate risk. 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 are utilized to manage interest rate risk associated with the Company's variable-rate borrowings.

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 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.

Additional Disclosures about Derivative Instruments and Hedging Activities

Cash Flow Hedges

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

As of September 30, 2010, the Company had outstanding natural gas, oil and NGL commodity forward contracts with notional volumes of 26,970,000 MMBtus, 292,000 Bbls and 255,500 Bbls, respectively, that were entered into to hedge forecasted natural gas, oil and NGL sales.

As of September 30, 2010, the total notional amount of the Company's receive-variable/pay-fixed interest rate swaps was $100.0 million. The Company includes the realized gain or loss on the hedged items (that is, interest on variable-rate borrowings) in the same line item – Interest expense, net of interest capitalized – as the offsetting gain or loss on the related interest rate swaps.

Information on the location and amounts of derivative fair values in the Consolidated Balance Sheet as of September 30, 2010 and December 31, 2009 and derivative gains and losses in the Consolidated Statement of Operations for the three and nine months ended September 30, 2010 and September 30, 2009 is as follows:

Fair Values of Derivative Instruments

Derivative Assets (Liabilities)

	Balance Sheet Location	Fair Value	
		September 30, 2010	December 31, 2009
Derivatives designated as hedging instruments		(In thousands)	
Interest rate swap		$ (97)	$ (399)

	Derivative instruments - current assets						
Interest rate swap	Derivative instruments - current liabilities		(148	)		(236	)
Commodity contracts - natural gas	Derivative instruments - current assets		33,118			9,382	
Commodity contracts - natural gas	Derivative instruments - non-current assets		9,467			-	
Commodity contracts - natural gas	Derivative instruments - non-current liabilities		-			(1,960	)
Commodity contracts - crude oil	Derivative instruments - current assets		(551	)		-	
Commodity contracts - crude oil	Derivative instruments - non-current assets		(317	)		-	
Commodity contracts - NGL	Derivative instruments - current assets		(1,024	)		-	
Commodity contracts - NGL	Derivative instruments - non-current assets		(330	)		-	
Total derivatives designated as hedging instruments		$	40,118		$	6,787	
Total derivatives not designated as hedging instruments		$	-		$	-	
Total derivatives		$	40,118		$	6,787	

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Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion) Three Months Ended September 30, 2010	September 30, 2009	Nine Months Ended September 30, 2010	September 30, 2009	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended September 30, 2010	September 30, 2009	Nine Months Ended September 30, 2010	September 30, 2009
	(In thousands)					(In thousands)			
Interest rate swap	$ (90)	$ (3,709)	$ (338)	$ 40,949	Interest expense, net of interest capitalized	$ (237)	$ -	$ (727)	$ (512)
Commodity contracts - natural gas	20,663	(550)	54,223	(1,679)	Natural gas sales	10,460	22,918	19,058	60,077
Commodity contracts - crude oil	(868)	-	(868)	-	Oil sales	-	-	-	-
Commodity contracts - NGLs	(1,354)	-	(1,354)	-	NGL sales	-	-	-	-
Total	$ 18,351	$ (4,259)	$ 51,663	$ 39,270	Total	$ 10,223	$ 22,918	$ 18,331	$ 59,565

(5) Fair Value Measurements

The Company adopted the authoritative guidance for fair value measurements effective January 1, 2008 for financial assets and liabilities and effective January 1, 2009 for non-financial assets and liabilities. 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, 2010, and the Company had no other material assets or liabilities that are reported at fair value on a non-recurring basis, no additional disclosures are provided as of September 30, 2010.

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.
- 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 swaps, natural gas and crude oil zero cost collars and interest rate swaps. The Company's money market funds represent cash equivalents which are investments 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, 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 counterparty quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties are further verified using relevant New York Mercantile Exchange ("NYMEX") futures contracts, exchange traded contracts and possibly third party broker quotes, if deemed necessary, 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, 2010. As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (liabilities):				
Money market funds	$ -	$ -	$ 35	$ 35
Commodity derivative contracts	-	-	40,363	40,363
Interest rate swap contracts	-	-	(245)	(245)
Total	$ -	$ -	$ 40,153	$ 40,153

	Fair value as of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (liabilities):				
Money market funds	$ -	$ -	$ 2,035	$ 2,035
Commodity derivative contracts	-	-	7,422	7,422
Interest rate swap contracts	-	-	(635)	(635)
Total	$ -	$ -	$ 8,822	$ 8,822

The determination of the fair values above incorporates various factors. These factors include the credit standing of the counterparties 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 current credit default swap values and default probabilities for each counterparty in determining fair value and recorded a downward adjustment to the fair value of its derivative assets in the amount of $0.2 million at September 30, 2010.

The following table sets forth a reconciliation of changes for the three and nine months ended September 30, 2010 and 2009 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Balance at beginning of period	$34,025	$47,810	$8,822	$43,397
Total Gains or (Losses) (Realized or Unrealized):				
Included in Earnings (1)	-	2	(1)	10
Included in Other Comprehensive Income	18,351	(4,259)	51,663	39,270
Purchases, Issuances and Settlements	(10,223)	(22,918)	(18,331)	(62,042)
Transfers in and out of Level 3	(2,000)	-	(2,000)	-
Balance at end of period	$40,153	$20,635	$40,153	$20,635

(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, 2010, 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, 2010 is $360.0 million. The Company calculated the fair value of its long-term debt as of September 30, 2010, 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 $371.5 million at September 30, 2010.

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(6) Asset Retirement Obligation

The following table provides a roll forward of the asset retirement obligations. Liabilities incurred during the period include additions to obligations as well as obligations that were assumed by the Company related to acquired properties. Liabilities settled during the period include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Activity related to the Company's asset retirement obligation ("ARO") is as follows:

	Nine Months Ended September 30, 2010 (In thousands)
ARO as of December 31, 2009	$ 28,920
Revision of previous estimates	322
Liabilities incurred during period	627
Liabilities settled during period	(1,965)
Accretion expense	1,682
ARO as of September 30, 2010	$ 29,586

As of September 30, 2010, the current portion of the total ARO is approximately $9.2 million and is included in Accrued liabilities and the long-term portion of ARO is approximately $20.4 million and is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Long-Term Debt

Senior Secured Revolving Line of Credit. The Company's amended and restated revolving credit agreement (the "Restated Revolver") provides for a senior secured revolving line of credit of up to $600.0 million and matures on July 1, 2012. 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. As of September 30, 2010, the borrowing base under the Restated Revolver was $345.0 million, reflecting a $30.0 million reduction of the base due to the issuance of $200.0 million aggregate principal amount of 9.500% Senior Notes due 2018 ("Senior Notes"). Amounts outstanding under the Restated Revolver bear interest at specified margins over LIBOR of 2.25% to 3.00%. Borrowings under the Restated Revolver are collateralized by liens on substantially all of the Company's assets, liens 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 equity interests of domestic subsidiaries. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. 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, 2010. The Company paid a facility fee on the total commitment of $4.6 million in April 2009. The Company took additional borrowings of $39.0 million on the Restated Revolver during the third quarter of 2010 and, as a result had $140.0 million outstanding with $205.0 million available for borrowing under the Restated Revolver as of September 30, 2010.

On October 19, 2010, the Company’s semi-annual borrowing base review was completed and the borrowing base under the Restated Revolver was increased to $365.0 million. The increase in borrowing base is correlated to an increase in the Company's reserve value and is net of an adjustment for the successful divestiture of non-core properties located in Arkansas, Texas and Louisiana. The borrowing base is subject to further adjustment pending the Pinedale and San Juan divestitures as discussed in Note 14, Subsequent Events.

Second Lien Term Loan. The Company’s amended and restated term loan (the “Restated Term Loan”) matures on October 2, 2012. As a result of the Company’s Senior Notes offering on April 15, 2010 (discussed below), the Company repaid the $80.0 million of variable rate borrowings under the Restated Term Loan during the second quarter of 2010 which bore interest at LIBOR plus 8.5% with a LIBOR floor of 3.5%. In accordance with authoritative guidance for derivative instruments and hedging activities, the Company evaluated the LIBOR floor as an embedded derivative and concluded that because the terms are clearly and closely related to the debt instrument, it does not represent an embedded derivative that must be accounted for separately. As of September 30, 2010, the Company had $20.0 million of fixed rate borrowings bearing interest at 13.75% under the Restated Term 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 of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. 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, 2010. The Company paid an original issue discount of $1.6 million and a facility fee of $0.9 million on the total commitment in April 2009. On April 15, 2010, Company paid an early termination premium of $1.3 million related to the early extinguishment of the outstanding $80.0 million variable rate borrowings. The Company also has the right to prepay the fixed portion of $20.0 million 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.

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Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes ("Senior Notes") due 2018. The Senior Notes were issued under an indenture (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 the Company's capital stock or purchase, repurchase, redeem, defease or retire our 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. Proceeds from the Senior Notes offering were used to repay $114.0 million on the Restated Revolver, $80.0 million of variable rate borrowings 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, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain substantially identical terms to the Senior Notes.

As of September 30, 2010, the Company had total outstanding borrowings of $360.0 million and the Company's weighted average borrowing rate was 7.23%.

(8) Income Taxes

The effective tax rate for the three and nine months ended September 30, 2010 was 37.6% and 38.1%, respectively, while the effective tax rate for the three and nine months ended September 30, 2009 was 40.2% and 36.8%, respectively. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to state income taxes and the non-deductibility of certain incentive compensation. As of September 30, 2010 and December 31, 2009, the Company had no unrecognized tax benefits. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2010, the Company has a deferred tax asset of $153.5 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. There is no valuation allowance recorded on the deferred tax asset as the Company believes it is more likely than not that the asset will be utilized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

(9) Commitments and Contingencies

The Company is party to various legal proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Net of available insurance and performance of contractual defense and indemnity 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.

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(10) Comprehensive Income (Loss)

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010		2009		2010		2009	
	(In thousands)							
Accumulated other comprehensive income, beginning of period		$20,123		$28,725		$4,259		$24,079
Net income (loss)	$8,850		$5,731		$20,425		$(228,367)	
Change in fair value of derivative hedging instruments	$18,351		$(4,259)		$51,663		$39,270	
Hedge settlements reclassed to income (loss)	(10,223)		(22,918)		(18,331)		(59,043)	
Tax provision related to hedges	(3,077)		10,123		(12,417)		7,365	
Total other comprehensive income	$5,051	$5,051	$(17,054)	$(17,054)	$20,915	$20,915	$(12,408)	$(12,408)
Comprehensive income (loss)	$13,901		$(11,323)		$41,340		$(240,775)	
Accumulated other comprehensive income, end of period		$25,174		$11,671		$25,174		$11,671

(11) Earnings (Loss) Per Share

Basic earnings (loss) 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In thousands)			
Basic weighted average number of shares outstanding	51,411	50,994	51,329	50,961
Dilution effect of stock option and awards at the end of the period (1)	662	297	721	-
Diluted weighted average number of shares outstanding	52,073	51,291	52,050	50,961
Anti-dilutive stock awards and shares	72	1,450	63	1,963

(1) Because the Company recognized a net loss for the nine months ended September 30, 2009, no unvested stock awards and options were included in computing earnings per share because the effect was anti-dilutive. In computing earnings per share, no adjustments were made to reported net income (loss).

(12) Geographic Area Information

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. Also, 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

The Company owns 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,	
	2010 (1)	2009 (1)	2010 (1)	2009 (1)
Natural gas, Oil and NGL Revenue	(In thousands)		(In thousands)	
Eagle Ford	$29,327	$288	$51,342	$356
South Texas	17,175	18,519	61,836	69,328
California	14,521	12,393	53,008	45,154
Rockies	6,366	4,498	21,379	15,900
Gulf Coast	580	3,305	6,081	18,594
Other Onshore	1,838	2,563	6,333	8,067
Total revenue, excluding gains on hedges	$69,807	$41,566	$199,979	$157,399

(1) Excludes the effects of hedging gains of $10.5 million and $19.1 million for the three and nine months ended September 30, 2010, respectively, and $22.9 million and $60.1 million for the three and nine months ended September 30, 2009, respectively.

(13) 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.

(14) Subsequent Events

On October 13, 2010, the Company entered into an additional costless collar transaction to hedge 600 Bbl/d of its expected crude oil production for January 2012 through December 2012. The costless collar has a floor price of $75.00 per Bbl and a ceiling price of $102.00 per Bbl through December 2012. On the same date, the Company entered into four additional NGL fixed price swaps to hedge 450 Bbl/d of its expected NGL production for January 2012 through December 2012 at an average price of $55.07 per Bbl, excluding the ethane component of the NGL barrel.

The Company closed the sale of the Arklatex assets on October 19, 2010. The divestiture for $37.1 million was effective as of August 1, 2010 and was subject to post-closing purchase price adjustments.

Also on October 19, 2010, the Company's semi-annual borrowing base review was completed and the borrowing base under the Restated Revolver was increased to $365.0 million. The increase in borrowing base is correlated to an increase in the Company's reserve value and is net of an adjustment for the successful divestiture of the Arklatex assets. The borrowing base is subject to further adjustment pending the Pinedale and San Juan divestitures.

The Company executed a purchase and sale agreement on October 22, 2010 for the divestiture of the Pinedale and San Juan assets. Although the agreement is subject to due diligence and other termination rights, the transaction is anticipated to close before December 31, 2010.

The decision has been made to close the Denver office effective January 1, 2011. The Company is consolidating its technical resources in Houston, Texas to capture efficiencies of operating in a central location. Management does not believe activities associated with the closing of the Denver office will have a material effect on the Company's financial position, results of operations or cash flows.

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,” “pr
“intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target” or “continue,” the negative of su
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.

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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 2009 Annual Report and in our subsequent reports on Form 10-Q. 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:

– supply and demand for oil and natural gas;

– changes in the price of oil and natural gas;

– general economic conditions, either internationally, nationally or in jurisdictions affecting our business;

– conditions in the energy and economic markets;

– our ability to access the capital markets on favorable terms or at all;

– our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;

– the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;

– failure of our joint interest partners to fund any or all of their portion of any capital program;

– the occurrence of property acquisitions, divestitures or joint ventures;

– oil and natural gas reserve levels;

– the effect of 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;

– future processing volumes and pipeline throughput;

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

– drilling and exploration risks;

– several possible new legislative initiatives and regulatory changes that could adversely impact our business and industry, including, but not limited to financial reform, including new requirements regarding swaps, national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, 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 and increased enforcement activities over the industry;

– 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;

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- 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, 2010 compared to the three and nine months ended September 30, 2009, and material changes in our financial condition since December 31, 2009. This discussion should be read in conjunction with our 2009 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, 2010 as compared to the same period for 2009:

- diluted earnings per share increased $0.06 to $0.17 for the three months ended September 30, 2010 from $0.11 for the three months ended September 30, 2009;

- average realized gas prices, including hedging, decreased $0.26 per Mcf, or 5%, to $5.33 per Mcf for the three months ended September 30, 2010 from $5.59 per Mcf for the three months ended September 30, 2009;

- average realized NGL prices decreased $0.12 per Bbl, or less than 1%, to $36.65 per Bbl for the three months ended September 30, 2010 from $36.77 per Bbl for the three months ended September 30, 2009;

- average realized oil prices increased $4.81 per Bbl, or 7%, to $69.09 per Bbl for the three months ended September 30, 2010 from $64.28 per Bbl for the three months ended September 30, 2009;

- total revenue, including the effects of hedging, increased $15.8 million, or 24%, to $80.3 million for the three months ended September 30, 2010 from $64.5 million for the three months ended September 30, 2009;

- 22 gross (22 net) wells were drilled with a net success rate of 95% for the three months ended September 30, 2010 compared to 9 gross (9 net) wells drilled with a net success rate of 78% for the same period in 2009;

- production on a Bcfe basis increased 20% to 13.3 Bcfe for the three months ended September 30, 2010 from 11.1 Bcfe for the three months ended September 30, 2009; and

- 33% of our revenue for the three months ended September 30, 2010 was generated from oil and NGL sales as compared to 16% for the same period in 2009, reflecting our shift to a higher liquids mix.

The following summarizes our performance for the nine months ended September 30, 2010 as compared to the same period for 2009:

- various acquisitions and divestitures were completed, including the divestiture of the Gulf Coast Texas State Waters Sabine Lake asset, a non-core property, for $10.2 million, and the acquisition of the remaining 30% working interest in the Catarina Field for $5.9 million;

- $200.0 million of 9.500% Senior Notes due in 2018 were issued in April 2010;

- diluted earnings per share increased $4.87 to $0.39 for the nine months ended September 30, 2010 from diluted loss per share of $4.48 for the nine months ended September 30, 2009;

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- average realized gas prices, including hedging, decreased $0.20 per Mcf, or 4%, to $5.29 per Mcf for the nine months ended September 30, 2010 from $5.49 per Mcf for the nine months ended September 30, 2009;

- average realized NGL prices increased $9.79 per Bbl, or 32%, to $40.18 per Bbl for the nine months ended September 30, 2010 from $30.39 per Bbl for the nine months ended September 30, 2009;

- average realized oil prices increased $21.29 per Bbl, or 42%, to $71.84 per Bbl for the nine months ended September 30, 2010 from $50.55 per Bbl for the nine months ended September 30, 2009;

- total revenue, including the effects of hedging, increased $1.5 million, or 1%, to $219.0 million for the nine months ended September 30, 2010 from $217.5 million for the nine months ended September 30, 2009;

- 116 gross (114 net) wells were drilled with a net success rate of 98% for the nine months ended September 30, 2010 compared to 36 gross (29 net) wells drilled with a net success rate of 83% for the same period in 2009;

- production on a Bcfe basis decreased 5% to 36.7 Bcfe for the nine months ended September 30, 2010 from 38.8 Bcfe for the nine months ended September 30, 2009; and

- 28% of our revenue for the nine months ended September 30, 2010 was generated from oil and NGL sales as compared to 14% for the same period in 2009, reflecting our shift to a higher liquids mix.

During 2008 and 2009, Rosetta transformed itself as a company by establishing a portfolio of domestic resource plays offering predictable, sustainable and profitable growth. We generated an inventory of low-cost drilling opportunities by increasing our positions in two key shale plays, primarily in the Eagle Ford area in South Texas and in the Southern Alberta Basin in northwest Montana. These efforts were funded through existing cash flows and when considered economically practical, asset divestitures aided in supplementing inadequate cash flows.

In the Eagle Ford shale, our acreage position currently stands at roughly 65,000 net acres. Approximately 41,000 acres have been delineated and are under development. Of the total net acreage, roughly 50,000 net acres are located in the liquids-rich area of the play. During the first nine months of 2010, we ran a minimum two-rig program in the Eagle Ford and expect to continue at that pace for the remainder of this year. Results from our 2010 wells are exceeding expectations and we have already begun to identify a significant level of future inventory from the play. In the second quarter of 2010, we added additional firm long-term gas transportation and processing agreements in the Gates Ranch area to our existing firm long-term and short-term gas transportation capacity rights. This infrastructure expansion is scheduled to be completed on or before December 1, 2010 and will relieve current constraints on takeaway from the Gates Ranch area. We believe these additions are sufficient to accommodate the expected additional gas production from the Gates Ranch property for the near future. Negotiations were also completed for additional gas processing capacity rights for portions of this production.

In addition to the Company's 41,000 net acres that have been successfully tested and delineated, the Company recently tested a 3,500 net acre position in central Dimmit County with the drilling and completion of the Light Ranch #1H. This previously untested block is part of the Company's 7,500 net acre Catarina leasehold position. The remaining untested 4,000 net acres at Catarina as well as an additional 16,500 net acres throughout the play remain untested as this time but are believed to be located in the liquids-rich window. We continue to evaluate opportunities to build our acreage position in the Eagle Ford play but only at leasehold acquisition costs that we believe are attractive and reasonable. In total, the Company expects to drill 28 Eagle Ford shale wells and complete approximately 20 wells for the year ended 2010.

Our progress in the Eagle Ford positions the Company to profitably grow production and reserves going forward. Ongoing success in this play has the ability to accelerate value creation by effectively capitalizing growth and shifting our product mix toward a higher percentage of liquids. Accordingly, we believe the program economics of the Eagle Ford play are superior to other inventory in our portfolio today and may provide some of the strongest returns among U.S. onshore basins.

In the less mature Southern Alberta Basin, we currently hold approximately 300,000 net acres. During 2009, we drilled or spud three wells across a large portion of our exploratory acreage position. Two were vertical wells and the third was drilled and completed as a horizontal well. During the second quarter of 2010, we conducted low-cost fracture stimulated completions in the existing vertical well sections of our 2009 drilled wells. Based on the results of these vertical tests, we drilled two wells of a planned eight-well vertical program that we believe represents the most cost effective way to delineate our extensive acreage position and establish commerciality of the play. Although the Southern Alberta Basin is still exploratory in nature, we are encouraged about the potential of this opportunity.

With success in the Eagle Ford and promising evaluations in the Southern Alberta Basin, we are significantly curtailing capital spending on our gas-prone assets given the relative economics and inventory upside from the shale plays. Initially, we announced a 2010 capital program of $280.0 million. We now expect to invest approximately $310.0 million, primarily reflecting completion design changes and service cost increases in the Eagle Ford play, as well as additional leasehold purchases in the Eagle Ford and Southern Alberta Basin areas. Although we are broadly committed to a fiscal strategy of internally funding our capital program, persistently weak gas prices have eroded cash flows and hence our ability to achieve this objective at the current time. As a result, we expanded our 2010 asset divestiture program to include the Arklatex, Pinedale and San Juan properties. We are willing to draw on our amended and restated revolving credit agreement (the “Restated Revolver”) to the extent additional funds are required and would consider other options for funding our capital program beyond 2010, including additional asset sales, and/or accessing the capital markets.

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On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes ("Senior Notes") due 2018. We used the proceeds from the Senior Notes offering to repay $80.0 million of variable rate borrowings under our amended and restated term loan (the “Restated Term Loan”), to repay $114.0 million under our Restated Revolver 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. As a result of the offering, the borrowing base under our Restated Revolver was reduced by $30.0 million to $345.0 million and our unused Restated Revolver availability was $205.0 million as of September 30, 2010 with total liquidity of over $229.0 million as of that date. With the completion of our semi-annual borrowing base review on October 19, 2010, the borrowing base was set at $365.0 million, reflecting an increase correlated with an increase in our reserve value and net of an adjustment for the divestiture of the Arklatex assets. The borrowing base is subject to further adjustment pending the Pinedale and San Juan divestitures.

While we are encouraged about having the inventory to achieve profitable growth in production and reserves, the operating environment for our industry continues to be very challenging. The outlook for natural gas continues to be weak. Access to some oilfield services is tight, especially for fracture stimulation services. This could impede our ability to execute programs on a timely basis. Our new plays require infrastructure, most notably in the Eagle Ford, which could also result in production delays. We have entered into a firm transportation agreement for delivery up to 152 MMcf/d of production from Gates Ranch on a new pipeline targeted for completion on or before December 1, 2010. The increased capacity is anticipated to accommodate current and projected production in the near future.

We attempt to manage risk in our business by carefully monitoring the environment, working closely with our suppliers and vendors, staying abreast of the marketplace, and moving at a deliberative pace in our new play programs so that we do not overcapitalize them. Nevertheless, regardless of how effectively we manage these risks, they represent threats to our ability to achieve our growth goals. As to building our asset base, we prefer organic opportunities, but we are also expanding our capability to evaluate and pursue acquisition opportunities that fit our business model. We believe this balanced approach is appropriate for long-term success; however, it is not our intention or desire to pursue acquisitions solely for the sake of growth, but rather that fit our strategic and economic objectives.

In order to ensure that we preserve the necessary financial flexibility, we work closely with our lenders to stay abreast of credit market conditions. Of note, our capital expenditures are primarily in areas where we act as operator and have high working interests. As a result, we do not believe we have significant exposure to joint interest partners who may be unable to fund their portion of any capital program and we monitor partner situations routinely.

Results of Operations

Revenues. Our revenues are derived from the sale of our natural gas, oil and NGL production, which includes the effects of contracts that qualify for hedge accounting. 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, 2010 was $80.3 million, which is an increase of $15.8 million, or 24%, from $64.5 million for the three months ended September 30, 2009. Total revenue, excluding the effects of hedging, for the three months ended September 30, 2010 was $69.8 million, which is an increase of $28.2 million, or 68%, from $41.6 million for the three months ended September 30, 2009. Approximately 33% of our revenue for the three months ended September 30, 2010 was attributable to oil and NGL sales as compared to 16% for the same period in 2009.

Total revenue, including the effects of hedging, for the nine months ended September 30, 2010 was $219.0 million, which is an increase of $1.5 million, or 1%, from $217.5 million for the nine months ended September 30, 2009. Total revenue, excluding the effects of hedging, for the nine months ended September 30, 2010 was $199.9 million, which is an increase of $42.5 million, or 27%, from $157.4 million for the nine months ended September 30, 2009. Approximately 28% of our revenue in the first nine months of 2010 was attributable to oil and NGL sales as compared to 14% for the same period in 2009.

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The following table presents information regarding our revenues (including the effects of hedging) and production volumes for the periods indicated:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	% Change Increase/ (Decrease)	2010	2009	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)					
Natural gas sales	$53,783	$54,207	(1 %)	$157,081	$187,238	(16 %)
Oil sales	15,406	4,435	247 %	33,162	16,116	106 %
NGL sales	11,078	5,842	90 %	28,794	14,122	104 %
Total revenue	$80,267	$64,484	24 %	$219,037	$217,476	1 %
Production:						
Gas (Bcf)	10.1	9.7	4 %	29.7	34.1	(13 %)
Oil (MBbls)	223.0	69.0	223 %	461.6	318.8	45 %
NGLs (MBbls)	302.3	158.9	90 %	716.6	464.7	54 %
Total Equivalents (Bcfe)	13.3	11.1	20 %	36.7	38.8	(5 %)
$ per unit:						
Avg. natural gas price per Mcf	$5.33	$5.59	(5 %)	$5.29	$5.49	(4 %)
Avg. natural gas price per Mcf, excluding hedging	4.29	3.23	33 %	4.65	3.73	25 %
Avg. oil price per Bbl	69.09	64.28	7 %	71.84	50.55	42 %
Avg. NGL price per Bbl	36.65	36.77	0 %	40.18	30.39	32 %
Avg. revenue per Mcfe	6.04	5.81	4 %	5.97	5.61	6 %

Natural Gas. For the three months ended September 30, 2010, natural gas revenue, including the effects of hedging, decreased by $0.4 million, or 1%, from the same period in 2009, to $53.8 million from $54.2 million. This decrease is primarily due to the decline in the average gas price, including the effects of hedging, offset by an increase in production during the third quarter of 2010. The average gas price, including the effects of hedging, decreased by $0.26 per Mcf from $5.59 per Mcf for the three months ended September 30, 2009 to $5.33 per Mcf for the same period in 2010. The effect of natural gas hedging activities on natural gas revenue for the three months ended September 30, 2010 was a gain of $10.5 million as compared to a gain of $22.9 million for the three months ended September 30, 2009.

For the nine months ended September 30, 2010, natural gas revenue, including the effects of hedging, decreased by $30.1 million, or 16%, from the same period in 2009, to $157.1 million from $187.2 million. This decrease is primarily due to the decrease in production during 2010 as a result of the curtailed capital drilling program in 2009. The average gas price, including the effects of hedging, decreased by $0.20 per Mcf from $5.49 per Mcf for the nine months ended September 30, 2009 to $5.29 per Mcf for the same period in 2010. The effect of natural gas hedging activities on natural gas revenue for the nine months ended September 30, 2010 was a gain of $19.1 million as compared to a gain of $60.1 million for the nine months ended September 30, 2009.

Crude Oil. For the three months ended September 30, 2010, oil revenue increased by $11.0 million, or 247%, to $15.4 million from $4.4 million for the same period in 2009. This increase is attributable to an increase in production by 223%, or 154.0 MBbls, to 223.0 MBbls for the three months ended September 30, 2010 from 69.0 MBbls for the three months ended September 30, 2009 due to newly drilled wells in the Eagle Ford play that flowed to sales in the third quarter of 2010. The average realized price also increased from $64.28 per Bbl for the three months ended September 30, 2009 to $69.09 per Bbl for the three months ended September 30, 2010.

For the nine months ended September 30, 2010, oil revenue increased by $17.1 million, or 106%, to $33.2 million from $16.1 million for the same period in 2009. This increase is attributable to an increase in production by 45%, or 142.8 MBbls, to 461.6 MBbls for the nine months ended September 30, 2010 from 318.8 MBbls for the nine months ended September 30, 2009 due to newly drilled wells in the Eagle Ford play that flowed to sales in the second and third quarters of 2010. The average realized price also increased from $50.55 per Bbl for the nine months ended September 30, 2009 to $71.84 per Bbl for the nine months ended September 30, 2010.

NGLs. For the three months ended September 30, 2010, NGL revenue increased by $5.3 million, or 90%, to $11.1 million from $5.8 million for the same period in 2009. This increase is attributable to an increase in production by 90%, or 143.4 MBbls, to 302.3 MBbls for the three months ended September 30, 2010 from 158.9 MBbls for the three months ended September 30, 2009 due to newly drilled wells in the Eagle Ford play that flowed to sales in the third quarter of 2010. The increase is offset by a marginal decline in the average realized price of $36.77 per Bbl for the three months ended September 30, 2009 to $36.65 per Bbl for the three months ended September 30, 2010.

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For the nine months ended September 30, 2010, NGL revenue increased by $14.7 million, or 104%, to $28.8 million from $14.1 million for the same period in 2009. This increase is attributable to an increase in production by 54%, or 251.9 MBbls, to 716.6 MBbls for the nine months ended September 30, 2010 from 464.7 MBbls for the nine months ended September 30, 2009 due to newly drilled wells in the Eagle Ford play that flowed to sales in the second and third quarters of 2010. The average realized price also increased from $30.39 per Bbl for the nine months ended September 30, 2009 to $40.18 per Bbl for the nine months ended September 30, 2010.

Operating Expenses

The following table presents information regarding our operating expenses:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2010	2009	% Change Increase/ (Decrease)	2010	2009	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)					
Lease operating expense	$11,486	$13,312	(14 %)	$39,473	$47,921	(18 %)
Production taxes	1,565	1,109	41 %	4,940	4,183	18 %
Depreciation, depletion and amortization	32,163	23,029	40 %	81,696	95,928	(15 %)
Impairment of oil and gas properties	-	-	-	-	379,462	(100 %)
General and administrative costs	12,560	10,414	21 %	35,693	32,358	10 %
$ per unit:						
Avg. lease operating expense per Mcfe	$0.86	$1.20	(28 %)	$1.08	$1.24	(13 %)
Avg. production taxes per Mcfe	0.12	0.10	20 %	0.13	0.11	18 %
Avg. DD&A per Mcfe	2.42	2.07	17 %	2.23	2.47	(10 %)
Avg. production costs per Mcfe (1)	3.28	3.27	0 %	3.30	3.71	(11 %)
Avg. G&A per Mcfe	0.94	0.94	0 %	0.97	0.83	17 %

(1) Average production costs per Mcfe include lease operating expense and depreciation, depletion and amortization (“DD&A”).

Lease Operating Expense. Lease operating expense decreased $1.8 million to $11.5 million from $13.3 million for the three months ended September 30, 2010 as compared to the three months ended September 30, 2009. The overall decrease is due primarily to reduced estimates for current year ad valorem expenses.

Lease operating expense decreased $8.4 million to $39.5 million from $47.9 million for the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2009. The overall decrease is due primarily to reduced estimates for current year ad valorem expenses, the divestiture of the Sabine Lake asset and overall lease operating expense reduction efforts.

Production Taxes. Production taxes as a percentage of unhedged natural gas, oil and NGL sales were 2.2% and 2.5%, for the three and nine months ended September 30, 2010, respectively, as compared to 2.7% for the three and nine months ended September 30, 2009, respectively. This decrease in rate was primarily due to certain production tax credits in the state of Texas.

Depreciation, Depletion and Amortization. DD&A expense increased $9.2 million to $32.2 million for the three months ended September 30, 2010 from $23.0 million for the three months ended September 30, 2009. The increase is due to an increase in production for the three months ended September 30, 2010 from the same period in 2009. The DD&A rate increased to $2.42 per Mcfe for the three months ended September 30, 2010 from $2.07 per Mcfe for the same period in 2009 primarily due to increased development costs in the Eagle Ford play.

DD&A expense decreased $14.2 million to $81.7 million for the nine months ended September 30, 2010 as compared to $95.9 million for the nine months ended September 30, 2009. The decrease is due to the full cost ceiling test impairment charges recognized during the first quarter of 2009. The DD&A rate decreased to $2.23 per Mcfe for the nine months ended September 30, 2010 from $2.47 per Mcfe for the same period in 2009 also due to the lower full cost asset base resulting from the first quarter 2009 impairment charges.

Impairment of Oil and Gas Properties. Based upon quarterly ceiling test computations using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of oil and gas, there was no write-down required to be recorded at September 30, 2010 and no write-down has occurred during the nine months ended September 30, 2010.

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Net capitalized costs of oil and natural gas properties did not exceed the cost center ceiling at September 30, 2009 and as such, the Company did not record a write-down at September 30, 2009. However, based upon the quarterly ceiling test computations using hedge adjusted market prices, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling at March 31, 2009. As such, a pre-tax, non-cash impairment expense of $379.5 million was recorded at March 31, 2009 and represents the only write-down for the nine months ended September 30, 2009.

General and Administrative Costs. General and administrative costs increased $2.2 million to $12.6 million for the three months ended September 30, 2010 from $10.4 million for the three months ended September 30, 2009. This increase is primarily the result of an increase of $2.4 million in stock based compensation expense, bonus accrual, and salaries, wages and benefits, a $0.3 million increase in contract services, and a $0.5 million increase in franchise taxes, repair and maintenance costs and other general and administrative expenses. This increase was offset by a decrease of $1.0 million related to the capitalization of geological and geophysical costs.

General and administrative costs increased $3.3 million to $35.7 million for the nine months ended September 30, 2010 as compared to $32.4 million for the nine months ended September 30, 2009. This increase is primarily the result of an increase of $7.0 million in stock based compensation expense, bonus accrual, and salaries, wages and benefits and an increase of $0.7 million of other general and administrative expenses. This increase was offset by a decrease of $2.4 million related to the capitalization of geological and geophysical costs, a decrease of $1.0 million related to the allocation of general and administrative expenses to joint venture partners and a decrease of $1.0 million related to contract services.

Total Other Expense

Total other expense includes Interest expense, net of interest capitalized; Interest income; and Other income/expense, net, and increased $1.2 million to $6.4 million for the three months ended September 30, 2010 from $5.2 million for the three months ended September 30, 2009. The increase in Total other expense was due to an increase in interest expense. The weighted average interest rate for the third quarter of 2010 was 7.39% compared to 6.20% for the same period in 2009. This increase in the weighted average interest rate was primarily due to the higher interest rate associated with the Senior Notes.

Total other expense increased $5.6 million to $19.5 million for the nine months ended September 30, 2010 from $13.9 million for the nine months ended September 30, 2009. The increase in Total other expense was due to an increase in interest expense. Long-term debt outstanding as of September 30, 2010 was $71.4 million higher as compared to September 30, 2009. The weighted average interest rate for the nine months ended September 30, 2010 was 7.01% compared to 4.83% for the same period in 2009. 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, 2010 was 37.6% and 38.1%, respectively, while the effective tax rate for the three and nine months ended September 30, 2009 was 40.2% and 36.8%, respectively. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to state income taxes and the non-deductibility of certain incentive compensation.

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our 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, 2010, we have a deferred tax asset of $153.5 million resulting primarily from the difference between the book basis and tax basis of our oil and natural gas properties and net operating loss carryforwards. We have concluded that it is more likely than not that this deferred tax asset will be realized through future taxable income generated by the production of our oil and natural gas properties.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow. We also maintain a revolving line of credit, which can be accessed as needed to supplement operating cash flow.

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

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Senior Secured Revolving Line of Credit. Our Restated Revolver provides for a senior secured revolving line of credit of up to $600.0 million and matures on July 1, 2012. 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. Our 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. A reduction in capital spending could result in a reduced level of reserves thus causing a reduction in the borrowing base. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.25% to 3.00%. 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 equity interests of domestic subsidiaries. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. 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, 2010. As a result of our Senior Notes offering on April 15, 2010, the borrowing base under our Restated Revolver was reduced by $30.0 million to $345.0 million and remained unchanged as of September 30, 2010. We took additional borrowings of $39.0 million on the Restated Revolver during the third quarter of 2010 and, as a result, had $140.0 million outstanding, with $205.0 million available for borrowing under the Restated Revolver as of September 30, 2010.

The Company’s semi-annual borrowing base review was completed on October 19, 2010 and the borrowing base under the Restated Revolver was increased to $365.0 million. The increase in borrowing base is correlated to an increase in the Company's reserve value and is net of an adjustment for the successful divestiture of non-core properties in Arkansas, Texas and Louisiana. The borrowing base is subject to further adjustment pending the Pinedale and San Juan divestitures.

Second Lien Term Loan. Our Restated Term Loan matures on October 2, 2012. Under the Restated Term Loan, as of September 30, 2010 we had $20.0 million of fixed rate borrowings bearing interest at 13.75%. The loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended after giving pro forma effect to acquisitions and divestitures. 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, 2010. On April 15, 2010, in connection with our issuance of the Senior Notes, we repaid all $80.0 million of variable rate borrowings under the Restated Term Loan together with accrued interest and a prepayment premium. We also have the right to prepay the fixed portion of $20.0 million of 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.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018. 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 the Company’s capital stock or purchase, repurchase, redeem, defease or retire our 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 the proceeds from the Senior Notes offering to repay $80.0 million of variable rate borrowings under our

Restated Term Loan, to repay $114.0 million under our Restated Revolver 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 substantially identical terms to the Senior Notes.

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Cash Flows

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

	Nine Months Ended September 30, 2010	2009
	(In thousands)	
Cash flows provided by operating activities	$ 133,551	$ 122,924
Cash flows used in investing activities	(234,044)	(82,008)
Cash flows provided by (used in) financing activities	63,479	(18,073)
Net (decrease)/increase in cash and cash equivalents	$ (37,014)	$ 22,843

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 continued to be a primary source of liquidity and capital used to finance our capital program.

Cash flows provided by operating activities were relatively flat for the nine months ended September 30, 2010 as compared to the same period for 2009.

Investing Activities. The primary driver of cash used in investing activities is capital spending.

Cash flows used in investing activities increased by $152.0 million for the nine months ended September 30, 2010 as compared to the same period for 2009. During the nine months ended September 30, 2010, we participated in the drilling of 116 gross wells as compared to the drilling of 36 gross wells during the same period in 2009.

Financing Activities. The primary drivers of cash provided by (used in) financing activities are borrowings and repayments on the revolving credit facility and 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 provided by financing activities increased by $81.6 million for the nine months ended September 30, 2010 as compared to the same period for 2009. The net increase is primarily related to the borrowings on the Restated Revolver of $64.0 million during the first nine months of 2010 and the net impact of the $200.0 million issuance of the Senior Notes and repayment of $80.0 million under the Restated Term Loan and $114.0 under the Restated Revolver.

Capital Expenditures and Requirements

The historical capital expenditures summary table is included in Items 1 and 2 Business and Properties in our 2009 Annual Report and is incorporated herein by reference.

Our capital expenditures for the nine months ended September 30, 2010 increased by $165.8 million to $251.7 million, from $85.9 million compared to the same period in 2009. During the nine months ended September 30, 2010, we participated in the drilling of 116 gross wells with the majority of these being in the Rockies region. At current commodity prices, our positive operating cash flow and cash on hand may not be sufficient to fund planned capital expenditures for 2010, which are projected to be $310.0 million, an increase of $30.0 million from the announced 2010 capital program. The increase in our planned capital expenditures primarily reflects leasehold purchases and service cost increases in the Eagle Ford play where the vast majority of our planned drilling capital is allocated.

We have limited discretion to adjust capital investment plans throughout the remainder of the year in response to market conditions. Should the availability of proceeds from possible divestitures be inadequate, we may draw on our Restated Revolver, if required.

Commodity Price Risk, Interest Rate Risk and Related Hedging Activities

The energy markets have historically been very volatile, and there can be no assurance that oil, NGL and natural gas prices will not be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, costless collars and put options. Although not risk free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby 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 and costless collars, which are intended to establish a fixed price or an average floor and ceiling price for 9% to 23%, 12%, and 7% of our expected production, respectively, for each year through 2012. Our fixed-price swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of natural gas, oil and NGLs without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected production from existing wells at inception of the hedge instruments.

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Borrowings under our Restated Revolver and Restated Term Loan mature on July 1, 2012 and October 2, 2012, respectively, and with respect to the Restated Revolver bear interest at a LIBOR-based rate while the $20.0 million outstanding under our Restated Term Loan bears interest at a fixed rate of 13.75%. After April 15, 2010, there was no ongoing interest rate risk under our Restated Term Loan due to the repayment of the $80.0 million variable rate borrowings. The exposure to LIBOR under the Restated Revolver exposes us to risk of earnings loss due to increases in market interest rates. To mitigate this exposure, we have entered into a series of interest rate swap agreements through December 2010. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into additional interest rate swap agreements in the future.

The following table sets forth the results of commodity and interest rate swap hedging transaction settlements:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Natural Gas	2010	2009	2010	2009
Quantity settled (MMBtu)	5,060,000	5,256,972	9,585,000	15,599,493
Increase in natural gas sales revenue (In thousands)	$10,460	$22,918	$19,058	$60,077
Interest Rate Swaps				
(Increase) in interest expense (In thousands)	$(237)	$-	$(727)	$(1,034)

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

As of September 30, 2010, our commodity and interest rate hedge positions were with counterparties that were also lenders in our credit facilities. This allows us to secure any margin obligation resulting from a negative change in the fair market value of the derivative contracts in connection with our credit obligations and eliminate the need for independent collateral postings. As of September 30, 2010, we had no deposits for collateral.

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. The United States Congress is currently considering legislation on climate change. In September 2009, the U.S. House of Representatives passed a comprehensive clean energy and climate bill (H.R. 2454, also known as “Waxman-Markey”). The U.S. Senate is working on a variety of proposed climate bills, including the American Power Act of 2010 (proposed by Senators Kerry and Lieberman). These bills have a variety of provisions and differences, but in substance they both propose a “cap and trade” approach to greenhouse gas regulation. Under such an approach, companies would be required 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. In addition to the prospect of federal legislation, 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) may act to regulate greenhouse gas emissions. In April 2007, the United States Supreme Court concluded that greenhouse gas emissions from automobiles were "air pollutants" within the meaning of the applicable provisions of the federal Clean Air Act. Relying in part on that precedent, in December 2009, the EPA released an Endangerment and Cause or Contribute Findings for Greenhouse Gases, which became effective in January 2010. This regulatory finding sets the foundation for future EPA greenhouse gas regulation under the Clean Air Act. The EPA also promulgated a new greenhouse gas reporting rule, which became effective in December 2009, and which requires facilities that emit more than 25,000 tons per year of carbon dioxide-equivalent emissions to prepare and file certain emission reports. The portion of the rule pertaining to fugitive and vented methane emissions from the oil and gas sector has not yet been incorporated into the final rule and remains proposed. If this portion of the proposed rule is ultimately promulgated, some of our facilities may be subject to the reporting requirements. On May 12, 2010, the EPA issued a new "tailoring" rule, which proposed and imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of carbon dioxide equivalent emissions. The EPA is considering additional rulemaking to apply these requirements to broader classes of emission sources by 2012, which may apply to some of our facilities. Finally, on April 12, 2010, the EPA proposed rules to expand the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. If adopted, these rules would require data collection beginning in 2011 and reporting beginning in 2012. Depending on the final outcome of these rulemakings, some of our facilities may be subject to these rules. 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.

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We recently mutually agreed with representatives of the Wyoming DEQ to settle the Notice of Violation we received on February 12, 2010 for $25,000.

Commitments and Contingencies

As is common within the 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 litigation matters and administrative claims arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe, net of available insurance and performance of contractual defense and indemnity obligations, where applicable, any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

In our 2009 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, income taxes and stock-based compensation.

We assess the impairment for oil and natural gas properties for the full cost accounting method on a quarterly basis 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 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, 2010, 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). 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, 2010. It is possible that a write-down of our oil and gas properties could occur in the future should oil and natural gas prices decline, we experience significant downward adjustments to the estimated proved reserves, and/or our commodity hedges settle and are not replaced.

We have entered into natural gas price hedging arrangements with respect to a portion of our expected production through 2012. As of September 30, 2010, 2,300,000 MMBtu and 2,760,000 MMBtu of our expected production were hedged using swaps and costless collars, respectively, with settlement in 2010, 5,475,000 MMBtu and 12,775,000 MMBtu of our expected production were hedged using swaps and costless collars, respectively, with settlement in 2011, and 3,660,000 MMBtu of our expected production were hedged using costless collars, with settlement in 2012. The swaps to settle in 2010 have an average price of $6.83 per MMBtu and the collars have floor and ceiling prices of $5.75 per MMBtu and $7.12 per MMBtu, respectively. The swaps to settle in 2011 have an average price of $5.85 per MMBtu and the collars have floor and ceiling prices of $5.79 per MMBtu and $7.27 per MMBtu, respectively. The collars to settle in 2012 have floor and ceiling prices of $5.75 per MMBtu and $7.15 per MMBtu, respectively. Approximately 83% of total hedged transactions represent hedged prices of commodities at the PG&E Citygate and Houston Ship Channel.

Additionally, we have entered into a crude oil price hedging arrangement with respect to a portion of our expected production for 2011. As of September 30, 2010, 292,000 Bbls of our expected production were hedged using a costless collar with settlement in 2011. The collar has floor and ceiling prices of $70.00 per Bbl and $90.05 per Bbl, respectively. The hedged transaction represents hedged prices of crude oil at West Texas Intermediate on the NYMEX.

Finally, we have entered into NGL price hedging arrangements, excluding the ethane component of the NGL barrel, with respect to a portion of our expected production for 2011. As of September 30, 2010, 255,500 Bbls of our expected production were hedged using swaps with settlement in 2011. The swaps have an average price of $51.74 per Bbl and include propane, butane, isobutane, and pentane. Approximately 50% of the total hedged transactions represent hedged NGL prices at Mont Belvieu Propane (Non-TET) OPIS.

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Our current cash flow hedge 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, 2010, we made no deposits for collateral. 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, 2010. We evaluated non-performance risk using current credit default swap values and default probabilities for each counterparty and recorded a downward adjustment to the fair value of our derivative assets in the amount of $0.2 million at September 30, 2010.

We utilize counterparty quotes to determine the valuation of our derivative instruments. Fair values derived from counterparties are further verified using the settled price as of September 30, 2010 for NYMEX futures contracts, exchange traded contracts, and possibly third party broker quotes, 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 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 oil, NGL and natural gas prices and interest rates. We use derivative instruments to manage our commodity price risk caused by fluctuating prices and our interest rate risk caused by fluctuating interest rates. 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 2009 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, 2010, we had open natural gas derivative hedges in an asset position with a fair value of $42.6 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $10.7 million, while a 10 percent decrease in natural gas prices would increase the fair value by approximately $10.9 million. The effects of these derivative transactions on our natural gas sales are discussed above under “Results of Operations – Natural Gas”.

As of September 30, 2010, we had open crude oil derivative hedges in a liability position with a fair value of $0.9 million. A 10 percent increase in crude oil prices would reduce the fair value by approximately $1.5 million, while a 10 percent decrease in crude oil prices would increase the fair value by approximately $1.4 million. The effects of these derivative transactions on our crude oil sales are discussed above under “Results of Operations – Crude Oil”.

As of September 30, 2010, we had open NGL derivative hedges in a liability position with a fair value of $1.4 million. A 10 percent increase in NGL prices would reduce the fair value by approximately $1.5 million, while a 10 percent decrease in NGL prices would increase the fair value by approximately $1.5 million. The effects of these derivative transactions on our NGL sales are discussed above under “Results of Operations – NGLs”.

Additionally, as of September 30, 2010, we had open interest rate swap hedges in a liability position of $0.2 million. A 10 percent increase in interest rates would increase the fair value by approximately $7.0 thousand, while a 10 percent decrease in interest rates would decrease the fair value by approximately $7.0 thousand. These fair value changes assume volatility based on prevailing market parameters as of September 30, 2010.

Our current cash flow hedge positions are with counterparties that are lenders in our credit facilities. Based upon communications with these counterparties, the obligations under these transactions are expected to continue to be met. We evaluated non-performance risk using credit default swap values and default probabilities for each counterparty and recorded a downward adjustment to the fair value of our derivative assets in the amount of $0.2 million as of September 30, 2010. We currently know of no circumstances that would limit access to our credit facility or require a change in our debt or hedging structure.

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, 2010. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2010, 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.

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There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2010 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 proceedings in the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, net of available insurance and performance of contractual defense and indemnity obligations, where applicable, we do not expect these matters to have a material adverse effect on our financial position, results of operations and our cash flows.

Item 1A. Risk Factors

Other than with respect to the risk factor below, there have been no material changes in our risk factors from those previously disclosed in Item 1A of our 2009 Annual Report and in Item 1A of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010.

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

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Reform Act), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Reform Act. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the act. The new requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in natural gas, oil and NGL commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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, 2010:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased

			Programs	Under the Plans or Programs
July 1 - July 31	2,950	$19.55	-	-
August 1 - August 31	958	21.69	-	-
September 1 - September 30	2,639	20.54	-	-
Total	6,547	$20.26	-	-

(1) All of the shares were surrendered by our employees and directors to pay tax withholding upon the vesting of restricted stock awards.

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Issuance of Unregistered Securities

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Removed and Reserved

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Registration Statement on Form S-1 of Rosetta Resources Inc. (the "Company") filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 10, 2008 (Registration No. 000-51801)).
31.1	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.

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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 5, 2010

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ROSETTA RESOURCES INC.

EXHIBIT INDEX

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