RAM ENERGY RESOURCES INC
Form 10-Q
November 07, 2011

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2011

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

Commission File Number: 000-50682

RAM Energy Resources, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

5100 East Skelly Drive, Suite 650, Tulsa, OK 74135

(Address of principal executive offices)

(918) 663-2800

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve 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 þ 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 þ 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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer o	Accelerated Filer þ	Non-Accelerated Filer o (Do not check if a 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 Exchange Act).

Yes o No þ

At November 7, 2011, 78,809,515 shares of the Registrant s Common Stock were outstanding.

Third Quarter 2011 Form 10-Q Report
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ITEM 1 FINANCIAL STATEMENTS

RAM Energy Resources, Inc.
Condensed Consolidated Balance Sheets
(in thousands, except share and per share amounts)

	September 30, 2011 (unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 44	$ 37
Accounts receivable:		
Oil and natural gas sales, net of allowance of $50 ($50 at December 31, 2010)	8,394	9,797
Joint interest operations, net of allowance of $479 ($479 at December 31, 2010)	443	631
Other, net of allowance of $11 ($48 at December 31, 2010)	452	155
Derivative assets	5,070	1,340
Prepaid expenses	540	1,657
Deferred tax asset	-	3,526
Inventory	3,883	3,382
Other current assets	537	4
Total current assets	19,363	20,529
PROPERTIES AND EQUIPMENT, AT COST:		
Proved oil and natural gas properties and equipment, using full cost accounting	708,984	689,472
Other property and equipment	10,471	10,072
	719,455	699,544
Less accumulated depreciation, amortization and impairment	(505,179)	(489,634)
Total properties and equipment	214,276	209,910
OTHER ASSETS:		
Deferred tax asset	26,289	31,001
Derivative assets	8,125	-
Deferred loan costs, net of accumulated amortization of $716 ($5,012 at December 31, 2010)	6,287	2,609
Other	988	952
Total assets	$ 275,328	$ 265,001
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable:		
Trade	$ 10,361	$ 17,149
Oil and natural gas proceeds due others	8,924	9,414
Other	3	452
Accrued liabilities:		

Compensation	1,524	1,948
Interest	475	2,448
Income taxes	318	699
Other	97	10
Deferred tax liability	2,891	-
Derivative liabilities	264	-
Asset retirement obligations	367	639
Long-term debt due within one year	146	127
Total current liabilities	25,370	32,886
DERIVATIVE LIABILITIES	303	203
LONG-TERM DEBT	200,252	196,965
ASSET RETIREMENT OBLIGATIONS	31,968	30,770
OTHER LONG-TERM LIABILITIES	10	10
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Common stock, $0.0001 par value, 100,000,000 shares authorized, 83,341,299 and 82,597,829 shares issued, 79,067,298 and 78,386,983 shares outstanding at September 30, 2011 and December 31, 2010, respectively	8	8
Additional paid-in capital	228,616	226,042
Treasury stock - 4,274,001 shares (4,210,846 shares at December 31, 2010) at cost	(7,093)	(6,976)
Accumulated deficit	(204,106)	(214,907)
Stockholders equity	17,425	4,167
Total liabilities and stockholders equity	$ 275,328	$ 265,001

The accompanying notes are an integral part of these condensed consolidated financial statements.

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RAM Energy Resources, Inc.
Condensed Consolidated Statements of Operations
(in thousands, except share and per share amounts)
(unaudited)

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
REVENUES AND OTHER OPERATING INCOME:				
Oil and natural gas sales				
Oil	$ 18,955	$ 18,290	$ 62,150	$ 56,898
Natural gas	2,548	4,923	8,252	16,170
NGLs	2,644	3,250	7,582	10,461
Total oil and natural gas sales	24,147	26,463	77,984	83,529
Realized gains (losses) on derivatives	76	(1,213)	(1,186)	(2,818)
Unrealized gains on derivatives	22,744	1,782	18,519	6,136
Other	39	51	124	125
Total revenues and other operating income	47,006	27,083	95,441	86,972
OPERATING EXPENSES:				
Oil and natural gas production taxes	1,391	1,518	4,280	4,565
Oil and natural gas production expenses	7,499	8,571	24,048	25,153
Depreciation and amortization	5,185	6,782	15,654	20,387
Accretion expense	409	452	1,223	1,288
Share-based compensation	872	813	2,227	2,284
General and administrative, overhead and other expenses, net of operator s overhead fees	3,100	2,932	10,913	10,694
Total operating expenses	18,456	21,068	58,345	64,371
Operating income	28,550	6,015	37,096	22,601
OTHER INCOME (EXPENSE):				
Interest expense	(3,637)	(5,767)	(13,750)	(17,116)
Interest income	1	20	4	24
Loss on interest rate derivatives	(203)	-	(698)	-
Other income (expense)	181	(268)	(572)	293
INCOME BEFORE INCOME TAXES	24,892	-	22,080	5,802
INCOME TAX PROVISION (BENEFIT)	13,116	(1,564)	11,279	(909)
Net income	$ 11,776	$ 1,564	$ 10,801	$ 6,711
BASIC INCOME PER SHARE	$ 0.15	$ 0.02	$ 0.14	$ 0.09
BASIC WEIGHTED AVERAGE SHARES OUTSTANDING	79,086,261	78,633,535	78,762,799	78,361,299

DILUTED INCOME PER SHARE	$ 0.15	$ 0.02	$ 0.14	$ 0.09
DILUTED WEIGHTED AVERAGE SHARES OUTSTANDING	79,086,261	78,633,535	78,762,799	78,361,299

The accompanying notes are an integral part of these condensed consolidated financial statements.

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RAM Energy Resources, Inc.
Condensed Consolidated Statements of Cash Flows
(in thousands)
(unaudited)

	Nine months ended September 30,	
	2011	2010
OPERATING ACTIVITIES:		
Net income	$ 10,801	$ 6,711
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation and amortization	15,654	20,387
Amortization of deferred loan costs	3,325	1,566
Non-cash interest	362	2,336
Accretion expense	1,223	1,288
Unrealized gain on commodity derivatives, net of premium amortization	(16,947)	(3,859)
Unrealized loss on interest rate derivatives	556	-
Deferred income tax provision (benefit)	11,129	(933)
Share-based compensation	2,227	2,284
Gain on disposal of other property and equipment	(22)	(38)
Other income	-	(574)
Changes in operating assets and liabilities-		
Accounts receivable	1,293	3,023
Prepaid expenses, inventory and other assets	49	1,598
Derivative premiums	4,889	(3,738)
Accounts payable and proceeds due others	(7,681)	1,603
Accrued liabilities and other	(2,386)	(1,717)
Income taxes payable	(381)	(473)
Asset retirement obligations	(278)	(161)
Total adjustments	13,012	22,592
Net cash provided by operating activities	23,813	29,303
INVESTING ACTIVITIES:		
Payments for oil and natural gas properties and equipment	(19,600)	(27,476)
Proceeds from sales of oil and natural gas properties	462	478
Payments for other property and equipment	(503)	(721)
Proceeds from sales of other property and equipment	11	4
Net cash used in investing activities	(19,630)	(27,715)
FINANCING ACTIVITIES:		
Payments on long-term debt	(235,222)	(37,618)
Proceeds from borrowings on long-term debt	238,166	36,261
Payments for deferred loan costs	(7,003)	-
Stock repurchased	(117)	(331)

Net cash used in financing activities		(4,176)		(1,688)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		7		(100)
CASH AND CASH EQUIVALENTS, beginning of period		37		129
CASH AND CASH EQUIVALENTS, end of period	$	44	$	29
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for income taxes	$	531	$	616
Cash paid for interest	$	12,036	$	13,518
DISCLOSURE OF NON CASH INVESTING AND FINANCING ACTIVITIES:				
Asset retirement obligations	$	(23)	$	147

The accompanying notes are an integral part of these condensed consolidated financial statements.

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RAM Energy Resources, Inc.
Notes to unaudited condensed consolidated financial statements

A SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, ORGANIZATION AND BASIS OF PRESENTATION

1. *Basis of Financial Statements*

The accompanying unaudited condensed consolidated financial statements present the financial position at September 30, 2011 and December 31, 2010 and the results of operations for the three and nine month periods ended September 30, 2011 and 2010, and cash flows for the nine month periods ended September 30, 2011 and 2010 of RAM Energy Resources, Inc. and its subsidiaries (the Company). These condensed consolidated financial statements include all adjustments, consisting of normal and recurring adjustments, which, in the opinion of management, are necessary for a fair presentation of the financial position and the results of operations for the indicated periods. The results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year ending December 31, 2011. Reference is made to the Company s consolidated financial statements for the year ended December 31, 2010 included in the Company s Annual Report on Form 10-K, for an expanded discussion of the Company s financial disclosures and accounting policies.

2. *Nature of Operations and Organization*

The Company operates exclusively in the upstream segment of the oil and natural gas industry with activities including the drilling, completion, and operation of oil and natural gas wells. The Company conducts the majority of its operations in the states of Texas, Oklahoma and Louisiana. The Company also owns and operates oil and natural gas properties in New Mexico, Mississippi and West Virginia.

3. *Use of Estimates*

The preparation of financial statements in conformity with accounting principles, generally accepted in the United States of America, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas reserves, amortization relating to oil and natural gas properties, asset retirement obligations, derivative instrument valuations and income taxes. The Company evaluates its estimates and assumptions on a regular basis. Estimates are based on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates used in preparation of the Company s financial statements. In addition, alternatives can exist among various accounting methods. In such cases, the choice of accounting method can have a significant impact on reported amounts.

4. *Income per Common Share*

Basic and diluted income per share is computed by dividing net income by the weighted average number of common shares outstanding for the period. A reconciliation of net income and weighted average shares used in computing basic and diluted net income per share are as follows (in thousands, except share and per share amounts):

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	Three months ended September 30,				Nine months ended September 30,			
	2011		2010		2011		2010	
Net income	$	11,776	$	1,564	$	10,801	$	6,711
Weighted average shares basic		79,086,261		78,633,535		78,762,799		78,361,299
Dilutive effect		-		-		-		-
Weighted average shares dilutive		79,086,261		78,633,535		78,762,799		78,361,299
Basic income per share	$	0.15	$	0.02	$	0.14	$	0.09
Diluted income per share	$	0.15	$	0.02	$	0.14	$	0.09

5. ***Subsequent Events***

The Company evaluates events and transactions that occur after the balance sheet date but before the financial statements are filed with the U.S. Securities and Exchange Commission (SEC).

B PROPERTIES AND EQUIPMENT

Under the full cost method of accounting, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at 10% (the Ceiling Limitation). In arriving at estimated future net revenues, estimated lease operating expenses, development costs, and certain production-related and ad valorem taxes are deducted. In calculating future net revenues, prices and costs are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the Ceiling Limitation on a quarterly and yearly basis. The excess, if any, of the net book value above the Ceiling Limitation is charged to expense in the period in which it occurs and is not subsequently reinstated. At September 30, 2011 and 2010, the net book value of the Company s oil and natural gas properties did not exceed the Ceiling Limitation.

C LONG-TERM DEBT

Long-term debt consists of the following (in thousands):

	September 30, 2011		December 31, 2010	
Credit facilities	$	200,000	$	196,521
Accrued payment-in-kind interest		-		221
Installment loan agreements		398		350
		200,398		197,092
Less amount due within one year		146		127
	$	200,252	$	196,965

Credit Facilities

In March 2011, the Company entered into new credit facilities. The new credit facilities, which replaced the Company s previous credit facility, include a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility. SunTrust Bank is the administrative agent for the revolving credit facility, and

Guggenheim Corporate Funding LLC is the administrative agent for the term loan facility. The borrowing base under the revolving credit facility at September 30, 2011 was $150.0 million. The borrowing base is reviewed and redetermined effective March 31 and September 30 of each year, and between scheduled redeterminations upon request. On September 30, 2011, the borrowing base was reaffirmed at $150.0 million based on the value of the Company s proved reserves at June 30, 2011. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the five-year term of the revolver, and bear interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan credit facility provides for payments of interest only during its 5.5-year term, with the interest rate being LIBOR plus 9.0% with a 2.0% LIBOR floor, or if in any period the Company elects to pay a portion of the interest under its term loan in kind, then the interest rate will be LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to the principal. At September 30, 2011, $125.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the term loan credit facility.

Advances under the new credit facilities are secured by liens on substantially all properties and assets of the Company and its subsidiaries. The new credit facilities contain representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on the Company s capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to indebtedness. The Company was in compliance with all of its covenants in the new credit facilities at September 30, 2011. The Company is required to maintain commodity hedges on a rolling basis for the first 12 months of not less than 60%, but not more than 85%, and for the next 18 months of not less than 50%, but not more than 85%, of projected quarterly production volumes, until the leverage ratio is less than or equal to 1.5 to 1.0. During June 2011, the Company entered into the First Amendment to the revolving credit facility. The First Amendment amended certain definitions affecting covenant calculations and modified the terms of the Company s natural gas derivative counterparty requirements.

The Company s previous credit facility entered into in November 2007, included a $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. The previous credit facility included a $250.0 million revolving credit facility and a $200.0 million term loan facility and an additional $50.0 million available under the term loan as requested by the Company and approved by the lenders. The initial amount of the $200.0 million term loan was advanced at closing. Funds advanced under the previous revolving credit facility initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The previous term loan provided for payments of interest only during its term, with the initial interest rate being LIBOR plus 7.5%. The borrowing base under the previous revolving credit facility was $145.0 million at December 31, 2010.

During June 2009, the Company entered into the Second Amendment to the previous credit facility. The Second Amendment amended certain definitions and certain financial and negative covenant terms to provide greater flexibility for the Company through the remaining term of the previous credit facility. Additionally, the Second Amendment increased the interest rates applicable to borrowings under both the revolver and the term loans. Advances under the revolver bore interest at LIBOR, with a minimum LIBOR rate, or floor, of 1.5%, plus a margin ranging from 2.25% to 3.0% based on a percentage of usage. The term loan bore interest at LIBOR, also with a floor of 1.5%, plus a margin of 8.5%, and an additional 2.75% of payment-in-kind interest that was added to the term loan principal balance on a monthly basis and paid at maturity. At December 31, 2010, $116.5 million was outstanding under the previous revolving credit facility and $80.2 million was outstanding under the term facility, including $0.2 million accrued payment-in-kind interest. Due to refinancing of the Company s outstanding debt prior to the issuance of the December 31, 2010 financial statements, the current portion of existing debt at December 31, 2010 was considered long-term. As previously noted, the Company entered into new credit facilities in March 2011. The proceeds from the new credit facilities were used to repay the previous credit facility. The Company expensed the remaining debt issuance costs associated with the previous credit facility totaling approximately $2.7 million in the first quarter of 2011.

D INCOME TAXES

Under guidance contained in Topic 740 of the Accounting Standards Codification™ (the Codification), deferred taxes are determined by applying the provisions of enacted tax laws and rates for the jurisdictions in which the Company operates to the estimated future tax effects of the differences between the tax basis of assets and liabilities and their reported amounts in the Company s financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company estimates its annual effective income tax rate in recording its quarterly provision for income taxes in the various jurisdictions in which the Company operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the quarter in which they occur. During the three and nine months ended September 30, 2011, the Company analyzed and made no adjustment to the valuation allowance. During the nine months ended September 30, 2010, the Company reduced the previously recorded valuation allowance by

$4.0 million due to its estimate of taxable income that it projected would be generated in the near future and more likely than not result in the realization of its deferred tax assets. The reduction in the valuation allowance was recorded as a discrete item in the second quarter of 2010.

The Company has calculated an estimated effective annual tax rate for the current annual reporting period, excluding any discrete items, of 41% as of September 30, 2011. The estimated annual rate differs from the statutory rate primarily due to the estimate of state income taxes and non-deductible expenses for the period. Based upon this estimated effective annual tax rate, the Company has recorded a tax provision of $9.2 million on pre-tax income of $22.1 million for the nine months ended September 30, 2011. The Company has also recorded additional tax expense of $2.1 million as a discrete item during the three months ended September 30, 2011 related to a revaluation of its deferred tax assets due to the limitations imposed on its net operating losses under Section 382 of the Internal Revenue Code. For the nine months ended September 30, 2010, the Company recorded a tax provision of $3.1 million on a pre-tax income of $5.8 million, based upon its estimated effective annual rate as of that period. In addition, the Company recorded a $4.0 million tax benefit resulting from a decrease in our valuation allowance as a discrete item during the nine months ended September 30, 2010.

E COMMITMENTS AND CONTINGENCIES

The Company is involved in legal proceedings and litigation in the ordinary course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company s financial position or results of operations.

In May of 2008, the Company drilled the Woolley #1-23 well in Oklahoma. On July 21, 2008 the Oklahoma Corporation Commission (the OCC) entered a forced pooling order for the Woolley #1-23 well and the Company acquired all of the working interests attributable to those parties who did not elect to participate in the drilling of the Woolley #1-23 well. Subsequent to the pooling, certain predecessors in interest that were erroneously omitted from the forced pooling order disputed the pooling order and sought a determination that they were entitled to share in the pooled acreage. The OCC determined that the omitted predecessors in interest were not entitled to share in the pooled acreage; however, the ruling of the OCC was reversed on appeal. As a result, the Company lost a portion of its working interest in the Woolley #1-23 well and in the McAlester formation of the 40-acre tract in which the well is located. During the second quarter of 2011, the Company recorded a charge to other expense of $0.8 million, a reduction in proved oil and gas properties of $0.2 million and a liability of $0.6 million to record the estimated settlement of the dispute. During August of 2011, the Company cash settled the $0.6 million liability.

F FAIR VALUE MEASUREMENTS

The Company measures the fair value of its derivative instruments according to the fair value hierarchy as set forth in Topic 820 of the Codification. Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The fair value of the Company s net derivative assets as of September 30, 2011 was $12.6 million and the fair value of the Company s net derivative assets as of December 31, 2010 was $1.1 million, based on Level 2 criteria. See Note G.

At September 30, 2011, the carrying value of cash, accounts receivable and accounts payable reflected in the Company s consolidated financial statements approximates fair value due to their short-term nature. Additionally, the carrying value of the Company s long-term debt under the credit facilities approximates fair value because the credit facilities carry a variable interest rate based on market interest rates. See Note C for discussion of long-term debt.

G DERIVATIVE CONTRACTS

The Company periodically utilizes various hedging strategies to achieve a more predictable cash flow. Various derivative instruments are used to manage the price received for a portion of the Company s future oil and natural gas production and interest rate swaps are used to manage the interest rate paid for a portion of the Company s outstanding debt.

During 2011 and 2010, the Company entered into numerous derivative contracts to manage the impact of oil and natural gas price fluctuations and as required by the terms of its credit facilities. During the first quarter of 2011, the Company also entered into interest rate swaps to manage the impact of interest rate fluctuations. The Company did not designate these transactions as hedges. Accordingly, all gains and losses on the derivative instruments during 2011 and 2010 have been recorded in the statements of operations.

The Company s oil and natural gas derivative positions at September 30, 2011, consisting of put/call collars, sold put options, which limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of

the put option sold, and bare purchased put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

Crude Oil (Bbls)							Natural Gas (Mmbtu)						
Collars							Collars						
	Floors		Ceilings		Put Options Sold			Floors		Ceilings		Bare Floors	
Year	Per Day	Price	Per Day	Price	Per Day	Price	Year	Per Day	Price	Per Day	Price	Per Day	Price
Q4 11	2,150	$80.00	2,150	$105.00	-	-	Q4 11	-	-	-	-	6,973	$4.17
Q1 12	2,000	$80.00	2,000	$105.00	1,000	$70.00	Q1 12	-	-	-	-	6,700	$4.35
Q2 12	2,000	$80.00	2,000	$105.00	1,000	$70.00	Q2 12	5,000	$4.00	5,000	$6.00	-	-
Q3 12	1,900	$92.63	1,900	$105.66	1,238	$70.00	Q3 12	5,000	$4.00	5,000	$6.00	-	-
Q4 12	1,750	$92.14	1,750	$104.83	1,138	$70.00	Q4 12	-	-	-	-	-	-
Q1 13	1,800	$95.28	1,800	$101.39	1,450	$70.00	Q1 13	-	-	-	-	-	-
Q2 13	1,650	$95.00	1,650	$99.93	1,325	$70.00	Q2 13	-	-	-	-	-	-
Q3 13	1,600	$95.00	1,600	$99.94	-	-	Q3 13	-	-	-	-	-	-
Q4 13	1,550	$95.00	1,550	$99.71	-	-	Q4 13	-	-	-	-	-	-
Q1 14	1,600	$95.00	1,600	$100.03	1,600	$70.00	Q1 14	-	-	-	-	-	-
Q2 14	1,500	$95.00	1,500	$99.13	1,500	$70.00	Q2 14	-	-	-	-	-	-

The Company s interest rate derivative positions at September 30, 2011, consisting of interest rate swaps, are shown in the following table:

Interest Rate Swaps (1)

Year	Notional Amount (in millions)	Fixed Rate	Counterparty Floating Rate (2)	Months Covered
2011	$50	2.51%	3-Month LIBOR	October - December
2012	$50	2.51%	3-Month LIBOR	January - December
2013	$50	2.51%	3-Month LIBOR	January - December
2014	$50	2.51%	3-Month LIBOR	January - March

(1) Settlement is paid to the Company if the counterparty floating rate exceeds the fixed rate and settlement is paid by the Company if the counterparty floating rate is below the fixed rate. Settlement is calculated as the difference in the fixed rate and the counterparty rate.

(2) Subject to a minimum rate of 2%.

The Company estimates the fair value of its derivative instruments based on published forward commodity price curves as of the date of the estimate, less discounts to recognize present values. The Company estimates the fair value of its derivatives using a pricing model which also considers market volatility, counterparty credit risk and additional criteria in determining discount rates. See Note F.

To determine the fair value of the Company s oil and natural gas derivative instruments, the discount rate used in the discounted cash flow projections was based on published LIBOR rates, Eurodollar futures rates and interest swap rates. The counterparty credit risk was determined by calculating the difference between the derivative counterparty s bond rate and published bond rates. The Company incorporates its credit risk when the derivative position is a liability by using its LIBOR spread rate.

Gross fair values of the Company s derivative instruments, prior to netting of assets and liabilities subject to a master netting arrangement, as of September 30, 2011 and December 31, 2010 and the consolidated statements of operations for the three and nine months ended September 30, 2011 and 2010 are as follows (in thousands):

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CONSOLIDATED BALANCE SHEETS

Gross Assets and Liabilities	Balance Sheet Location	Fair Value As of September 30, 2011 (unaudited)	Fair Value As of December 31, 2010
Current Assets - Oil and natural gas derivative assets	Current Assets - Derivative assets	$ 6,997	$ 1,904
Other Assets - Oil and natural gas derivative assets	Long-Term Assets - Derivative assets	13,001	-
Other Assets - Oil and natural gas derivative assets	Long-Term Liabilities - Derivative liabilities	-	207
Current Liabilities - Oil and natural gas derivative liabilities	Current Assets - Derivative assets	(1,927)	(564)
Current Liabilities - Interest rate swaps derivative liabilities	Current Liabilities - Derivative liabilities	(264)	-
Long-Term Liabilities - Oil and natural gas derivative liabilities	Long-Term Assets - Derivative assets	(4,876)	-
Long-Term Liabilities - Oil and natural gas derivative liabilities	Long-Term Liabilities - Derivative liabilities	-	(410)
Long-Term Liabilities - Interest rate swaps derivative liabilities	Long-Term Liabilities - Derivative liabilities	(303)	-
Total Derivatives Not Designated as Hedging Instruments		$ 12,628	$ 1,137

CONSOLIDATED STATEMENTS OF OPERATIONS

Income Statement Location	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Type of Derivative
Revenue - Unrealized gains on derivatives	$ 22,744	$ 1,782	$ 18,519	$ 6,136	Oil and natural gas derivatives - unrealized
Revenue - Realized gains (losses) on derivatives	$ 76	$ (1,213)	$ (1,186)	$ (2,818)	Oil and natural gas derivatives - realized
Other Income (Expense) - Loss on interest rate derivatives	$ (138)	$ -	$ (556)	$ -	Interest rate derivatives - unrealized

Other Income (Expense) - Loss on interest rate derivatives	Interest rate derivatives - realized			
	$ (65)	$ -	$ (142)	$ -

During April 2011, pursuant to the Company s new credit facilities entered into in March 2011, the Company was required to reduce the volume of its existing crude oil and natural gas derivatives so it would not exceed the maximum allowable volumes for future production periods and to novate derivative contracts to counterparties that are lenders within the new credit facilities. During the second quarter of 2011, the Company recognized $0.9 million in realized losses on the unwinding of the excess crude oil and natural gas derivatives and the $0.5 million in fees paid to complete the novation, both of which are included in realized gains and losses on derivatives in the income statement.

H SHARE-BASED COMPENSATION

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in Topic 718 of the Codification. The guidance requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

On May 8, 2006, the Company s stockholders approved its 2006 Long-Term Incentive Plan (the Plan). The Company reserved a maximum of 2,400,000 shares of its common stock for issuances under the Plan. The Plan includes a provision that, at the request of a grantee, the Company may repurchase shares to satisfy the grantee s federal and state income tax withholding requirements. All repurchased shares will be held by the Company as treasury stock. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares

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to be issued under the Plan from 2,400,000 to 6,000,000. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 6,000,000 to 7,400,000. As of September 30, 2011, 1,216,801 shares of common stock remained reserved for issuance under the Plan.

As of September 30, 2011, the Company had $3.8 million of unrecognized compensation related to common stock awards granted under the Plan. That cost is expected to be recognized over a weighted-average period of two years. The related compensation recognized during the three and nine months ended September 30, 2011 was $0.9 million and $2.5 million, respectively, and during the three and nine months ended September 30, 2010 was $0.8 million and $2.3 million, respectively. During the three and nine months ended September 30, 2011, $0.7 million and $2.1 million, respectively, of recognized compensation was recorded as compensation expense and $0.2 million and $0.4 million, respectively, was recorded as capitalized internal costs. During the three and nine months ended September 30, 2010, all recognized compensation was recorded to compensation expense.

In May 2011, the Company granted 1,530,500 stock appreciation rights (SARs) under the Plan at an exercise price of $1.73 per share, which was the weighted average closing price of the Company s common stock on the date of grant. Compensation expense related to the SARs is based on fair value re-measured at each reporting period and recognized over the vesting period (generally four years). As of September 30, 2011, the fair value calculation resulted in $0.1 million expense recognized during the three and nine months ended September 30, 2011. The SARs expire ten years from date of grant and upon exercise. The Company will settle the SARs in cash, net of the applicable taxes.

The Company uses the Black-Scholes option pricing model to compute the fair value of the SARs. The following assumptions were used in calculating fair value:

The risk-free interest rate is based on the zero coupon United States Treasury yield for the expected life of the grant.

The dividend yield on the Company s common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The volatility of the Company s common stock is based on volatility of the market price of the Company s common stock over a period of time equal to the expected term and ending on the grant date.

I SUBSEQUENT EVENTS

On October 7, 2011, the Company announced the retirement of certain Company officers and a Company-wide reorganization of its operating and administrative functions (the Reorganization). The Reorganization was approved by the Company s Board of Directors on October 4, 2011. As part of the Reorganization, the retirement and termination of employment of the affected officers and employees started during October of 2011 and will be completed in full by June 2012.

As part of the Reorganization, the Board of Directors authorized the Company to offer certain severance benefits to the affected officers and employees on terms specified by the Board (collectively, the Severance Program). The estimated total expense of the Severance Program is approximately $2.6 million, which includes approximately $1.8 million in one-time severance payments and approximately $0.8 million of stock compensation expense related to the acceleration of restricted stock awards.

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ITEM 2 MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS

General

We are an independent oil and natural gas company engaged in the development, acquisition, exploitation, exploration and production of oil and natural gas properties, primarily in Texas, Oklahoma and Louisiana. Our producing properties are located in highly prolific basins with long histories of oil and natural gas operations.

Principal Properties

Our principal oil and natural gas properties are located in the following fields:

Texas: La Copita (Starr County), Electra/Burkburnett (Wichita and Wilbarger Counties);

Oklahoma: Fitts-Allen (Pontotoc and Seminole Counties); and

Louisiana: Lake Enfermer (Lafourche Parish).

We also own and operate other oil and natural gas properties in Texas, Oklahoma, Louisiana, New Mexico, Mississippi and West Virginia.

In August 2011, we entered into an agreement in principle to sell a majority interest in our Electra/Burkburnett field, located in Wichita and Wilbarger Counties, Texas, to Argent Energy Trust, a recently formed Canadian energy trust. The sale is contingent upon the successful completion of the initial public offering, or IPO, of trust units, the negotiation and execution of a definitive purchase and sale agreement and execution of an agreement for the further development of the property with us continuing to serve as operator following the closing. Due to the recent market conditions, the possible sale of our interest in our Electra/Burkburnett properties has been put on hold pending such improvement in market conditions as will permit completion of the Argent IPO. The offering of trust units of Argent Energy Trust will be made within the United States only by Argent to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the Securities Act). The securities to be offered by Argent have not been registered under the Securities Act or any state securities laws, and unless so registered, may not be offered or sold in the United States except pursuant to an exemption from, or in a transition not subject to, the registration requirements of the Securities Act and applicable state securities law.

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Net Production, Unit Prices and Costs

The following table presents certain information with respect to our oil and natural gas production, and prices and costs attributable to all oil and natural gas properties owned by us, for the three and nine months ended September 30, 2011. Average realized prices reflect the actual realized prices received by us, before and after giving effect to the results of our derivative contract settlements. Our derivative activities are financial, and our production of oil, natural gas liquids, or NGLs, and natural gas, and the average realized prices we receive from our production, are not affected by our derivative arrangements.

	Three Months Ended September 30, 2011		Nine Months Ended September 30, 2011	
Production volumes:				
Oil (MBbls)		213		661
NGL (MBbls)		45		136
Natural gas (MMcf)		615		1,985
Total (MBoe)		361		1,128
Average sale prices received:				
Oil (per Bbl)	$	88.99	$	94.02
NGL (per Bbl)	$	58.76	$	55.75
Natural gas (per Mcf)	$	4.14	$	4.16
Total per Boe	$	66.89	$	69.13
Cash effect of derivative contracts:				
Oil (per Bbl)	$	(0.34)	$	(4.61)
NGL (per Bbl)	$	-	$	-
Natural gas (per Mcf)	$	0.24	$	0.94
Total per Boe	$	0.21	$	(1.05)
Average prices computed after cash effect of settlement of derivative contracts:				
Oil (per Bbl)	$	88.65	$	89.41
NGL (per Bbl)	$	58.76	$	55.75
Natural gas (per Mcf)	$	4.38	$	5.10
Total per Boe	$	67.10	$	68.08
Expenses (per Boe):				
Oil and natural gas production taxes	$	3.85	$	3.79
Oil and natural gas production expenses	$	20.77	$	21.32
Amortization of full cost pool	$	13.69	$	13.22
General and administrative	$	8.59	$	9.67
Cash interest	$	9.22	$	10.67
Cash taxes	$	0.14	$	0.47

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Acquisition, Development and Exploration Capital Expenditures

The following table presents information regarding our net costs incurred in our acquisitions of proved and unproved properties, and our development and exploration activities during the three and nine months ended September 30, 2011 (in thousands):

	Three months ended September 30, 2011	Nine months ended September 30, 2011
Development and exploratory costs	$ 5,830	$ 18,883
Proved property acquisition costs	270	717
Total costs incurred	$ 6,100	$ 19,600

During the quarter ended September 30, 2011, we participated in the drilling of 14 gross (11.5 net) development wells and two gross (2.0 net) exploration wells. Eight gross (8.0 net) development wells were capable of production. Six gross (3.5 net) development wells were either drilling or waiting on completion as of September 30, 2011. Two gross (2.0 net) exploration wells were waiting on completion at September 30, 2011.

Results of Operations

Quarter Ended September 30, 2011 Compared to Quarter Ended September 30, 2010

The following tables summarize our oil and natural gas production volumes, average sale prices (without regard to derivative contract settlements) and period-to-period comparisons for the periods indicated:

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Three Months Ended September 30, 2011					
Aggregate net Production					
Oil (MBbls)	116	76	14	7	213
NGLs (MBbls)	37	5	-	3	45
Natural Gas (MMcf)	363	99	119	34	615
MBoe	214	98	34	15	361

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Three Months Ended September 30, 2010					
Aggregate net Production					
Oil (MBbls)	134	81	23	9	247
NGLs (MBbls)	85	2	-	4	91
Natural Gas (MMcf)	802	208	167	38	1,215
MBoe	353	118	51	19	541
Change in MBoe	(139)	(20)	(17)	(4)	(180)
% change in MBoe	-39.4%	-16.9%	-33.3%	-21.1%	-33.3%

	Three months ended September 30, 2011	2010	Increase
Average sale prices:			
Oil (per Bbl)	$ 88.99	$ 74.05	20.2%
NGL (per Bbl)	$ 58.76	$ 35.71	64.5%
Natural gas (per Mcf)	$ 4.14	$ 4.05	2.2%
Per Boe	$ 66.89	$ 48.91	36.8%

In December 2010, we sold assets located in Texas and Oklahoma for net proceeds including post-closing adjustments of $48.8 million. The following table provides pro forma results for 2010 excluding those sold properties to assist our description of results of operations:

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	Three months ended September 30, 2010		
	Actual	Sold Assets	Pro Forma
Oil and natural gas sales (in thousands):			
Oil	$ 18,290	$ 280	$ 18,010
Natural gas	4,923	1,127	3,796
NGLs	3,250	1,102	2,148
Total oil and natural gas sales	$ 26,463	$ 2,509	$ 23,954
Production expenses (in thousands):			
Oil and natural gas production taxes	$ 1,518	$ 127	$ 1,391
Oil and natural gas production expenses	$ 8,571	$ 473	$ 8,098
Production volumes (MBoe):			
Texas	353	73	280
Oklahoma	118	15	103
Other	70	-	70
Total production	541	88	453

Oil and natural gas sales decreased $2.3 million, or 9%, to $24.1 million for the three months ended September 30, 2011, as compared to $26.5 million for the three months ended September 30, 2010. Excluding assets sold, oil and natural gas sales increased by $0.2 million for the three months ended September 30, 2011, as compared to the same period in 2010. This increase was driven by higher commodity prices during the 2011 period, offset by decreased production.

Production volumes decreased 33% for the three months ended September 30, 2011 as compared to the same period last year. Excluding the activities related to the asset divestitures, our production volume decreased 20% for the three months ended September 30, 2011 as compared to the same period last year primarily due to a shut-in of one well as a result of a major workover in Louisiana and normal production declines. Production from our Texas fields decreased 66 MBoe in the third quarter, excluding asset sales, due to normal production declines from new wells drilled in 2010. Drilling activity included eight gross (8.0 net) development wells which were capable of production and five gross (3.5 net) development wells that were either drilling or waiting on completion in our Texas fields. Production from our Oklahoma fields decreased 5 MBoe in the third quarter, excluding asset sales, primarily due to natural production declines. Drilling activity in Oklahoma included two gross (2.0 net) exploratory wells. Production from our Louisiana fields decreased 17 MBoe in the third quarter 2011 due to a shut-in of one well and normal production declines. We did not drill any new wells in our Louisiana fields during the third quarter of 2011.

The average realized sales prices on a Boe basis increased substantially for the three months ended September 30, 2011, as compared to the same period in 2010. The average realized sales price for oil was $88.99 per barrel for the three months ended September 30, 2011, an increase of 20%, compared to $74.05 per barrel for the same period in 2010. The average realized sales price for NGLs was $58.76 per barrel for the three months ended September 30, 2011, an increase of 65%, compared to $35.71 per barrel for the same period in 2010. The average realized sales price for natural gas was $4.14 per Mcf for the three months ended September 30, 2011, an increase of 2%, compared to $4.05 per Mcf for the same period in 2010. The positive impact from the 37% increase in total average price per Boe in the third quarter of 2011 did not fully offset the impact of asset sales and normal production declines, causing oil and natural gas sales for the third quarter to decline to $24.1 million compared to $26.5 million in the prior year period.

We recorded income before income taxes of $24.9 million for the quarter ended September 30, 2011, as compared to zero income before income taxes for the quarter ended September 30, 2010. Excluding unrealized gains on derivatives of $22.7 million, our adjusted income before income taxes for the quarter ended September 30, 2011 was $2.2 million. Excluding unrealized gains on derivatives of $1.8 million, our adjusted loss before income taxes for the quarter ended September 30, 2010 was $1.8 million.

Realized and Unrealized Gain (Loss) from Commodities Derivatives. For the quarter ended September 30, 2011, our gain from derivatives was $22.8 million, compared to $0.6 million for the quarter ended September 30, 2010. Our gains and losses during these periods were the net result of recording actual contract settlements, the premiums for our derivative contracts, and unrealized gains and losses attributable to mark-to-market values of our derivative contracts at the end of the periods.

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	Three months ended September 30,	
	2011	2010
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (72)	$ (1,157)
Natural gas	148	(56)
Realized gains (losses)	76	(1,213)
Mark-to-market gains:		
Oil	22,333	98
Natural gas	411	1,684
Unrealized gains	22,744	1,782
Realized and unrealized gains	$ 22,820	$ 569

Oil and Natural Gas Production Taxes. Excluding asset sales, our oil and natural gas production taxes remained flat at $1.4 million for the quarter ended September 30, 2011 as compared to the year ago quarter. Most production taxes are based on realized prices at the wellhead, while Louisiana production taxes are based on volumes for natural gas and values for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, our oil and natural gas production taxes were approximately 6% for each of the quarters ended September 30, 2011 and 2010.

Oil and Natural Gas Production Expense. Our oil and natural gas production expenses were $7.5 million for the quarter ended September 30, 2011, a decrease of $0.6 million, or 7%, from the $8.1 million, excluding asset sales, for the quarter ended September 30, 2010. The decrease is primarily due to decreased production volumes, decline in nonrecurring lease operating expenses as well as lower property taxes and utility costs during the 2011 period. Our oil and natural gas production expense was $20.77 per Boe for the quarter ended September 30, 2011 compared to $15.84 per Boe for the quarter ended September 30, 2010, an increase of 31%. The increase per Boe is primarily due to the asset sales, as the sold assets in 2010 were predominantly shale gas producing assets which had relatively lower lease operating expenses per Boe. As a percentage of oil and natural gas sales, oil and natural gas production expense was 31% for the quarter ended September 30, 2011, as compared to 32% for the quarter ended September 30, 2010. This decrease is due to the decline in production expenses as well as higher commodity prices in the 2011 period.

Amortization and Depreciation Expense. Our amortization and depreciation expense decreased $1.6 million, or 24%, for the quarter ended September 30, 2011, as compared to the quarter ended September 30, 2010. The decline was a result of a decrease in production during the 2011 period, offset by a higher depletion rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $4.9 million was $13.69 per Boe for the quarter ended September 30, 2011, as compared to $6.5 million, or $12.06 per Boe, for the quarter ended September 30, 2010.

Accretion Expense. Topic 410 of the Codification, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded accretion expense of $0.4 million for the quarter ended September 30, 2011, compared to $0.5 million for the quarter ended September 30, 2010. The decrease was related to the sold assets offset by changes in our estimates.

Share-Based Compensation. From time to time, our Board of Directors grants restricted stock awards and/or stock appreciation rights (SARs) under our 2006 Long-Term Incentive Plan. Each of the restricted stock grants vests in equal increments over the vesting period provided for the particular award. All currently unvested restricted stock awards provide for vesting periods from one to five years. The share-based compensation expense attributable to restricted stock grants is calculated using the closing price per share on each of the grant dates and will be recognized over their respective vesting periods. Share-based compensation expense attributable to SARs is based on the fair value re-measured at each reporting period and recognized over the four-year vesting period. The fair value calculation resulted in $0.1 million of compensation expense recognized for the three months ended September 30, 2011. For the quarter ended September 30, 2011, we recognized a total of $0.9 million share-based compensation related to restricted stock awards as compared to $0.8 million for the comparable quarter for the previous year. The increase was primarily due to a higher number of shares outstanding in the 2011 period. During the three months ended September 30, 2011, $0.7 million of recognized compensation related to restricted stock awards was recorded as compensation expense and $0.2 million was recorded as capitalized internal costs.

General and Administrative Expense. For the quarter ended September 30, 2011, our general and administrative expense was $3.1 million, compared to $2.9 million for the quarter ended September 30, 2010, an increase of $0.2 million, or 6%. The increase was primarily due to higher employee related costs in the 2011 period.

Interest Expense. We recorded interest expense of $3.6 million for the quarter ended September 30, 2011, as compared to $5.8 million for the third quarter of the previous year. The decrease in interest expense was due to lower interest rates and lower average outstanding borrowings throughout the 2011 period. Our blended interest rate as of September 30, 2011 and 2010 was 6.2% and 8.2%, respectively.

Loss on Interest Rate Derivatives. We incurred $0.2 million net realized and unrealized loss attributable to mark-to-market value of interest rate swaps in the third quarter of 2011. We had no interest rate derivatives in effect in the year ago quarter.

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Other Income (Expense). For the three months ended September 30, 2011, our other income was $0.2 million, compared to other expense of $0.3 million for the three months ended September 30, 2010. The decrease in other expense is primarily due to a charge relating to pipe inventory write-off in the 2010 period.

Income Taxes. For the three months ended September 30, 2011, we recorded income tax expense of $11.0 million on pre-tax income of $24.9 million. We have also recorded additional tax expense of $2.1 million as a discrete item during the three months ended September 30, 2011 related to the revaluation of our deferred tax assets due to the limitations imposed on our net operating losses under Section 382 of the Internal Revenue Code. For the three months ended September 30, 2010, we recorded income tax benefit of $1.6 million.

Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010

The following tables summarize our oil and natural gas production volumes, average sale prices (without regard to derivative contract settlements) and period-to-period comparisons for the periods indicated:

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Nine Months Ended September 30, 2011					
Aggregate net Production					
Oil (MBbls)	369	224	46	22	661
NGLs (MBbls)	116	10	-	10	136
Natural Gas (MMcf)	1,219	286	377	103	1,985
MBoe	688	282	109	49	1,128

	Texas	**Oklahoma**	**Louisiana**	**Other**	**Total**
Nine Months Ended September 30, 2010					
Aggregate net Production					
Oil (MBbls)	425	244	62	26	757
NGLs (MBbls)	262	7	-	11	280
Natural Gas (MMcf)	2,440	644	514	116	3,714
MBoe	1,094	358	148	56	1,656
Change in MBoe	(406)	(76)	(39)	(7)	(528)
% change in MBoe	-37.1%	-21.2%	-26.4%	-12.5%	-31.9%

	Nine months ended September 30, 2011	**2010**	**Increase/ (Decrease)**
Average sale prices:			
Oil (per Bbl)	$ 94.02	$ 75.16	25.1%
NGLs (per Bbl)	$ 55.75	$ 37.36	49.2%
Natural gas (per Mcf)	$ 4.16	$ 4.35	-4.4%
Per Boe	$ 69.13	$ 50.44	37.1%

In December 2010, we sold assets located in Texas and Oklahoma for net proceeds including post-closing adjustments of $48.8 million. The following table provides pro forma results for the nine months ended September 30, 2010 excluding those sold properties to assist our description of results of operations:

	Nine months ended September 30, 2010		
	Actual	Sold Assets	Pro Forma
Oil and natural gas sales (in thousands):			
Oil	$ 56,898	$ 957	$ 55,941
Natural gas	16,170	4,001	12,169
NGLs	10,461	3,875	6,586
Total oil and natural gas sales	$ 83,529	$ 8,833	$ 74,696
Production expenses (in thousands):			
Oil and natural gas production taxes	$ 4,565	$ 380	$ 4,185
Oil and natural gas production expenses	$ 25,153	$ 1,418	$ 23,735
Production volumes (MBoe):			
Texas	1,094	244	850
Oklahoma	358	49	309
Other	204	-	204
Total production	1,656	293	1,363

Oil and natural gas sales decreased $5.5 million, or 7% to $78.0 million for the nine months ended September 30, 2011, as compared to $83.5 million for the same period in 2010. Excluding asset sales, oil and natural gas sales increased $3.3 million for the nine months ended September 30, 2011 as compared to the same period in 2010. This increase was driven primarily by higher commodity prices during the 2011 period, partially offset by decreased production.

Production volumes decreased 32% as compared to the same period last year. Excluding the activities related to the asset divestitures, our production volume decreased 17% as compared to the same period last year primarily due to a shut-in of one well as a result of a major workover in Louisiana and normal production declines. Production from our Texas fields decreased 162 MBoe for the first nine months of 2011, excluding asset sales, due to a decline in well performance in our South Texas gas properties and from normal production declines. Drilling activity included 33 gross (30.8 net) development wells in our Texas fields. Of the 33 gross development wells in our Texas fields, 28 gross (27.3 net) wells were capable of production and five gross (3.5 net) wells were either drilling or waiting on completion. Production from our Oklahoma fields decreased 27 MBoe for the first nine months of 2011, excluding asset sales, primarily due to natural production declines. Drilling activity in Oklahoma included one gross (0.2 net) development well and nine gross (9.0 net) exploratory wells. Production from our Louisiana fields decreased 39 MBoe for the first nine months of 2011 due to a shut-in of one well and normal production declines. We did not drill any new wells in our Louisiana fields during the nine months ended September 30, 2011.

The average realized sales prices increased substantially for the nine months ended September 30, 2011, as compared to the same period in 2010. The average realized sales price for oil was $94.02 per barrel for the nine months ended September 30, 2011, an increase of 25%, compared to $75.16 per barrel for the same period in 2010. The average realized sales price for NGLs was $55.75 for the nine months ended September 30, 2011, an increase of 49%, compared to $37.36 per barrel for the same period in 2010. The average realized sales price for natural gas was $4.16 per Mcf for the nine months ended September 30, 2011, a decrease of 4%, compared to $4.35 per Mcf for the same period in 2010. The positive impact from the 37% increase in total average price per Boe in the first nine months of 2011 did not fully offset the impact of asset sales and normal production declines, causing oil and natural gas sales for the first nine months of 2011 to decline to $78.0 million compared to $83.5 million in the same period in 2010.

We recorded income before income taxes of $22.1 million for the nine months ended September 30, 2011, an increase of $16.3 million, as compared to $5.8 million for the nine months ended September 30, 2010. Excluding unrealized gains on derivatives of $18.5 million and debt extinguishment and loan amortization costs of $2.7 million, our adjusted income before income taxes for the nine months ended September 30, 2011 was $6.3 million. Excluding unrealized gains on derivatives of $6.1 million, our adjusted loss before income taxes for the nine months ended September 30, 2010 was $0.3 million.

Realized and Unrealized Gain (Loss) from Commodities Derivatives. For the nine months ended September 30, 2011, our gain from derivatives was $17.3 million, compared to $3.3 million for the nine months ended September 30, 2010. Our gains and losses during these periods were the net result of recording actual contract settlements, the premiums for our derivative contracts, and unrealized gains

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and losses attributable to mark-to-market values of our derivative contracts at the end of the periods. During the nine months ended September 30, 2011, we recognized $0.9 million in realized losses on the unwinding of the excess crude oil and natural gas derivatives and $0.5 million in fees paid to complete the novation of derivative contracts to counterparties that are lenders within our new credit facilities, both of which are included with other settlements of $0.2 million in realized gains and losses on derivatives and required under the terms of the new credit facilities.

	Nine months ended September 30,	
	2011	**2010**
	(in thousands)	
Contract settlements and premium costs:		
Oil	$ (3,044)	$ (3,088)
Natural gas	1,858	270
Realized losses	(1,186)	(2,818)
Mark-to-market gains (losses):		
Oil	19,606	3,577
Natural gas	(1,087)	2,559
Unrealized gains	18,519	6,136
Realized and unrealized gains	$ 17,333	$ 3,318

Oil and Natural Gas Production Taxes. Our oil and natural gas production taxes were $4.3 million for the nine months ended September 30, 2011, compared to $4.2 million, excluding asset sales, for the comparable nine months of the previous year. The increase is due principally to higher commodity prices in the 2011 period. Production taxes vary by state. Most production taxes are based on realized prices at the wellhead, while Louisiana production tax is based on volumes for natural gas and value for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of oil and natural gas sales, oil and natural gas production taxes were 5% for the nine months ended September 30, 2011 and 2010.

Oil and Natural Gas Production Expense. Our oil and natural gas production expenses were $24.0 million for the nine months ended September 30, 2011, an increase of $0.3 million, or 1%, from the $23.7 million, excluding asset sales, for the nine months ended September 30, 2010. For the nine months ended September 30, 2011, our oil and natural gas production expense was $21.32 per Boe compared to $15.19 per Boe for the nine months ended September 30, 2010, an increase of 40%. The increase per Boe is primarily due to the asset sales, as the sold assets in 2010 were predominantly shale gas producing assets which had relatively lower lease operating expenses per Boe. As a percentage of oil and natural gas sales, oil and natural gas production expense was 31% for the nine months ended September 30, 2011, as compared to 30% for the nine months ended September 30, 2010. This increase results from the decrease in oil and natural gas sales due to a decline in production in the 2011 period.

Amortization and Depreciation Expense. Our amortization and depreciation expense decreased $4.7 million, or 23%, for the nine months ended September 30, 2011, compared to the nine months ended September 30, 2010. The decrease was a result of a decrease in production during the 2011 period, offset by a higher depletion rate per Boe. On an equivalent basis, our amortization of the full-cost pool of $14.9 million was $13.22 per Boe for the nine months ended September 30, 2011, an increase per Boe of 12% compared to $19.6 million, or $11.83 per Boe for the nine months ended September 30, 2010.

Accretion Expense. Topic 410 of the Codification, Accounting for Asset Retirement Obligations, includes, among other things, the reporting of the fair value of asset retirement obligations. Accretion expense is a function of changes in fair value from period-to-period. We recorded $1.2 million for the nine months ended September 30, 2011, compared to $1.3 million for the first nine months in 2010. The decrease is primarily due to the sold assets offset by changes in our estimates.

Share-Based Compensation. From time to time, our Board of Directors grants restricted stock awards and/or SARs under our 2006 Long-Term Incentive Plan. Each of the restricted stock grants vests in equal increments over the vesting period provided for the particular award. All currently unvested restricted stock awards provide for vesting periods from one to five years. The share-based compensation on the restricted stock grants was calculated using the closing price per share on each of the grant dates, and the total share-based compensation on all restricted stock grants will be recognized over their respective vesting periods. Share-based compensation expense attributable to SARs is based on the fair value re-measured at each reporting period and recognized over the four-year vesting period. The fair value calculation resulted in $0.1 million of compensation expense recognized for the nine months ended September 30, 2011. For the nine months ended September 30, 2011, we recognized a total of $2.5 million share-based compensation related to restricted stock awards compared to $2.3 million for the nine months ended September 30, 2010. The increase was primarily due to a higher number of shares outstanding in the 2011 period. During the nine months ended September 30, 2011, $2.1 million of recognized compensation related to restricted stock awards was recorded as compensation expense and $0.4 million was recorded as capitalized internal costs.

General and Administrative Expense. For the nine months ended September 30, 2011, our general and administrative expense was $10.9 million, compared to $10.7 million for the nine months ended September 30, 2010, an increase of $0.2 million, or 2%.The increase was a result of higher employee related costs in the 2011 period.

Interest Expense. We recorded interest expense of $13.8 million for the nine months ended September 30, 2011, as compared to $17.1 million for the first nine months of the previous year. Of that $13.8 million, we incurred $2.7 million in debt extinguishment costs and $0.4 million in payment-in- kind interest related to our old credit facility in the first nine months of 2011. The decrease in interest expense was due to lower interest rates and lower average outstanding borrowings throughout the 2011 period. Our blended interest rate as of September 30, 2011 and 2010 was 6.2% and 8.2%, respectively.

Loss on Interest Rate Derivatives. We incurred $0.7 million net realized and unrealized loss attributable to interest rate swaps for the nine months ended September 30, 2011. Our realized and unrealized loss was the net result of recording actual contract settlements and unrealized losses attributable to the mark-to-market values of our interest rate swap contract at the end of the period. We had no interest rate derivatives in effect in the nine months ended September 30, 2010.

Other Income (Expense). For the nine months ended September 30, 2011, our other expense was $0.6 million, compared to other income of $0.3 million for the nine months ended September 30, 2010. The increase in other expense is primarily due to a litigation settlement recorded in 2011. For the nine months ended September 30, 2010, we reduced a contingency accrual by $0.6 million related to settlement of pending litigation offset by a charge relating to pipe inventory write-off.

Income Taxes. For the nine months ended September 30, 2011, we recorded income tax expense of $9.2 million on pre-tax income of $22.1 million. We have also recorded additional tax expense of $2.1 million as a discrete item during the nine months ended September 30, 2011 related to the revaluation of our deferred tax assets due to the limitations imposed on our net operating losses under Section 382 of the Internal Revenue Code. For the nine months ended September 30, 2010, we recorded income tax expense of $3.1 million on pre-tax income of $5.8 million. In addition, we recorded a $4.0 million tax benefit resulting from a decrease in our valuation allowance as a discrete item during the nine months ended September 30, 2010.

Liquidity and Capital Resources

As of September 30, 2011, we had cash and cash equivalents of less than $0.1 million, and $25.0 million of nominal availability under our revolving credit facility. In March 2011, we entered into new credit facilities including a $250.0 million first lien revolving credit facility with an initial $150.0 million borrowing base and a $75.0 million second lien term loan facility. Under our new credit facilities, through September 30, 2011, additional borrowings will not be limited by the leverage ratio covenant in our revolving loan agreement provided our Modified EBITDA for the preceding four fiscal quarters exceeds $47.4 million. Our Modified EBITDA for the four fiscal quarters ending September 30, 2011 was $47.8 million. Management believes that borrowings currently available to us under our credit facilities and anticipated cash flows from operations will be sufficient to satisfy our currently expected capital expenditures, working capital, and debt service obligations for the foreseeable future. At September 30, 2011, we had $200.4 million of indebtedness outstanding, including $125.0 million under our revolving credit facility, $75.0 million under our term loan credit facility and $0.4 million in other indebtedness. As of September 30, 2011, we had an accumulated deficit of $204.1 million and a working capital deficit of $6.0 million.

Credit Facilities . In March 2011, we entered into new credit facilities. The new facilities, which replaced our previous facility, include a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility. SunTrust Bank is the administrative agent for the revolving facility, and Guggenheim Corporate Funding, LLC is the administrative agent for the term loan facility. The current borrowing base under the revolving credit facility is $150.0 million. The borrowing base is reviewed and redetermined effective March 31 and September 30 of each year, and between scheduled redeterminations upon request. On September 30, 2011, the borrowing base was reaffirmed at $150.0 million based on the value of our proved reserves at June 30, 2011. Funds advanced under the revolving credit facility may be paid down and re-borrowed during the five-year term of the revolver, and bear interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan credit facility provides for payments of interest only during its 5.5-year term, with the interest rate being LIBOR plus 9.0% with a

2.0% LIBOR floor, or if in any period we elect to pay a portion of the interest under our term loan in kind, then the interest rate will be LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal.

Advances under our credit facilities are secured by liens on substantially all of our properties and assets. The credit facilities contain representations, warranties and covenants customary in transactions of this nature, including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio, minimum interest coverage ratio, maximum leverage ratio and a required ratio of asset value to total indebtedness. We are required to maintain commodity hedges on a rolling basis for the first 12 months of not less than 60%, but not more than 85%, and for the next 18 months of not less than 50% but not more than 85%, of our projected quarterly production volumes, until the leverage ratio is less than or equal to 1.5 to 1.0. At September 30, 2011, our commodity hedging represented approximately 65% of our projected production volumes through June 30, 2014. During June 2011, we entered into the First Amendment to the revolving credit facility. The First Amendment amended certain definitions affecting covenant calculations and modified the terms of our natural gas derivative counterparty requirements.

Our previous credit facility entered into November 2007 included a $500.0 million credit facility with Guggenheim Corporate Funding, LLC, for itself and on behalf of other institutional lenders. This facility included a $250.0 million revolving credit facility, a $200.0 million term loan facility, and an additional $50.0 million available under the term loan as requested by us and approved by the lenders. The entire amount of the $200.0 million term loan was advanced at closing. The borrowing base under our previous revolving credit facility was $145.0 million at December 31, 2010. Funds advanced under the revolving credit facility initially bore interest at LIBOR plus a margin ranging from 1.25% to 2.0% based on a percentage of usage. The term loan portion of our credit facility initially provided for payments of interest only during its five-year term, with the initial interest rate being LIBOR plus 7.5%.

On June 26, 2009, we renegotiated certain terms of our previous credit facility to provide us greater flexibility in complying with certain of the financial covenants under the loan agreement. In exchange for the added flexibility afforded by these changes to the credit facility, we agreed to increase the base cash interest rate on both the revolving credit facility and the term loan credit facility by 1% per annum, establish a LIBOR floor of 1.5% and pay an additional 2.75% per annum of non-cash, payment-in-kind, or PIK, interest on the term portion of the facility. Accrued PIK interest was added to the principal balance of the term loan on a monthly basis and was paid in connection with the closing of the new credit facilities in March 2011.

In December 2010, we used $33.8 million in proceeds from asset sales to pay down the term facility and $24.0 million in proceeds from asset sales to pay down the revolving credit facility. PIK interest of $3.0 million was added to the term facility in 2010, and $0.4 million was added to the term facility in the first quarter of 2011, bringing the balance of the term facility to $80.6 million at the date of the closing of the new credit facilities on March 14, 2011.

Our ability to comply with the financial covenants in our new credit facilities may be affected by events beyond our control and, as a result, in future periods we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facilities. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit facilities. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. At September 30, 2011, we were in compliance with all of the financial covenants under our credit facilities.

At-The-Market Program . On March 17, 2011, we filed a prospectus supplement under which we may, from time to time, sell up to $25.0 million of our common stock through an at-the-market equity distribution program (the At-The-Market Program). Shares would be offered pursuant to the prospectus supplement dated March 17, 2011 to our base prospectus dated February 24, 2010, which was filed as part of our effective shelf registration statement. As of September 30, 2011, we had made no sales of common stock through the At-The-Market Program.

Cash Flow From Operating Activities . Our cash flow from operating activities is comprised of three main items: net income, adjustments to reconcile net income to cash provided (used) before changes in working capital, and changes in working capital. For the nine months ended September 30, 2011, our net income was $10.8 million, as compared to $6.7 million for the nine months ended September 30, 2010. Adjustments (primarily non-cash items such as depreciation and amortization, unrealized (gains) losses and deferred income taxes) were $17.5 million for the nine months ended September 30, 2011, compared to $22.5 million for the first nine months of 2010, a decrease of $5.0 million. The change in unrealized (gains) losses and depreciation and amortization partially offset by the change in deferred income taxes caused most of this decrease. Working capital changes for the nine months ended September 30, 2011 were a negative $4.5 million compared to working capital changes of $0.1 million for the nine months ended September 30, 2010. For the nine months ended September 30, 2011 and 2010, in total, net cash provided by operating activities was $23.8 million and $29.3 million, respectively.

Cash Flow From Investing Activities . For the nine months ended September 30, 2011, net cash used in our investing activities was $19.6 million, consisting of $20.1 million in payments for oil and gas properties and other equipment offset by $0.5 million in proceeds from sales of property and equipment. For the nine months ended September 30, 2010, net cash used in our investing activities was $27.7 million.

Cash Flow From Financing Activities . For the nine months ended September 30, 2011, net cash used in our financing activities was $4.2 million, compared to $1.7 million for the nine months ended September 30, 2010. During the first nine months of 2011, we received proceeds of $238.2 million from borrowings on long-term debt. We also reduced our long-term debt by $235.2 million, paid $7.0 million for deferred loan costs, and incurred $0.1 million in common stock repurchased from participants under our 2006 Long-Term Incentive Plan to net settle withholding tax liability. During the first nine months of 2010, we received proceeds of $36.3 million from borrowings on long-term debt, which was offset by $37.6 million of payments made to reduce our long term debt and $0.3 million in common stock repurchased from participants under our 2006 Long-Term Incentive Plan to net settle withholding tax liability.

Capital Commitments

We have revised our budget to $27.5 million for non-acquisition capital expenditures in 2011 related to:

- developmental drilling and recompletions ($13.5 million);
- exploration, including leasehold acquisition, seismic and exploratory drilling ($7.0 million); and
- geological, geophysical, contingencies and capitalized general and administrative costs ($7.0 million).

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In our 2011 non-acquisition capital budget for developmental drilling and recompletions, we have allocated $7.9 million for continued development of our Electra/Burkburnett area, $2.8 million for recompletions in our Louisiana properties, $0.8 million for recompletions in our South Texas properties and $2.0 million for reworking and production enhancement operations in other fields, including our Fitts and Allen fields in Oklahoma.

During the nine months ended September 30, 2011, we had capital expenditures of $19.6 million relating to our oil and natural gas operations, of which $9.2 million was allocated to developmental drilling and recompletions, $5.4 million was allocated to exploration, including leasehold acquisition, seismic and exploratory drilling, and $5.0 million was allocated to geological, geophysical, contingencies and capitalized general and administrative costs.

The amount and timing of our capital expenditures for calendar year 2011 may vary depending on a number of factors, including prevailing market prices for oil and natural gas, the favorable or unfavorable results of operations actually conducted, projects proposed by third party operators on jointly owned acreage, development by third party operators on adjoining properties, rig and service company availability, and other influences that we cannot predict.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that cash flows from operations and the availability under our revolving credit facility will be sufficient to satisfy our budgeted non-acquisition capital expenditures, working capital and debt service obligations for the foreseeable future. The actual amount and timing of our future capital requirements may differ materially from our estimates as a result of, among other things, changes in product pricing and regulatory, technological and competitive developments. Sources of additional financing available to us may include commercial bank borrowings, vendor financing, asset sales and the sale of equity or debt securities. We cannot provide any assurance that any such financing will be available on acceptable terms or at all.

The credit markets are undergoing significant volatility. Many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to the current credit market crisis includes our revolving credit facility, counterparty risks related to our trade credit and risks related to our cash investments.

Our revolving credit facility matures in March 2016. Our term loan facility matures in September 2016. Should the current tightness in the credit markets continue, future extensions of our credit facility may contain terms that are less favorable than those of our current credit facility.

Current market conditions also elevate the concern over our cash deposits, which totaled approximately $2.3 million at September 30, 2011, but fluctuate throughout the year, and counterparty risks related to our trade credit. Our cash accounts and deposits with any financial institution that exceed the amount insured by the Federal Deposit Insurance Corporation are at risk in the event one of these financial institutions fails. We sell our crude oil, natural gas and NGLs to a variety of purchasers. Some of these parties are not as creditworthy as we are and may experience liquidity problems. Non-performance by a trade creditor could result in losses.

Subsequent Events

On October 7, 2011, we announced the retirement of certain of our officers and a Company-wide reorganization of our operating and administrative functions (the Reorganization). The Reorganization was approved by the Board of Directors on October 4, 2011. As part of the Reorganization, the retirement and termination of employment of the affected officers and employees started during October 2011 and will be completed in full by June 2012.

As part of the Reorganization, we were authorized by the Board of Directors to offer severance benefits to the affected officers and employees on terms specified by the Board (collectively, the Severance Program). The estimated total expense of the Severance Program is approximately $2.6 million, which includes approximately $1.8 million in one-time severance payments and approximately $0.8 million of stock compensation expense related to the acceleration of restricted stock awards.

ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Exposure to market risk is managed and monitored by our senior management. Senior management approves the overall investment strategy that we employ and has responsibility to ensure that the investment positions are consistent with that strategy and the level of risk acceptable to us. The carrying amounts reported in our consolidated balance sheets for cash and cash equivalents, trade receivables and payables, installment notes and variable rate long-term debt approximate their fair values.

Interest Rate Sensitivity

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents and the interest rate paid on our borrowings. In March 2011, we entered into an interest rate swap agreement to manage our cash flow on refinanced debt. Under the agreement, $50.0 million of our debt is subject to a fixed rate of 2.51%, with a swap floating rate of 3-month LIBOR, subject to a 2.0% floor.

Our long-term debt as of September 30, 2011, is denominated in U.S. dollars. Our debt has been issued at variable rates, and as such, interest expense would be impacted by interest rate changes. The new revolving credit facility entered into March 2011 is not subject to LIBOR floors, and the impact of 100-basis point increase in LIBOR interest rates would have resulted in an increase in interest expense of

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approximately $1.3 million annually based on the $125.0 million balance of our revolver as of September 30, 2011. LIBOR rates were less than 100-basis points as of September 30, 2011, so any decrease in interest rates would have resulted in a nominal decrease in interest expense under our revolver as of September 30, 2011. The term loan portion of our new credit facility includes a 2.0% LIBOR floor. The impact of a 100-basis point increase in LIBOR rates above our 2.0% floor would result in an increase in interest expense under our term loan of $0.3 million annually based on the $25.0 million balance of our term loan which is not subject to the interest rate swap as of September 30, 2011. A 100-basis point decrease would have no effect on interest expense under our term loan until the LIBOR rate exceeds 2.0%.

Commodity Price Risk

Our revenue, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. We currently sell most of our oil and natural gas production under market price contracts.

During the quarter ended September 30, 2011, Shell Energy North America-US accounted for $16.7 million, or approximately 69%, of our revenue from the sales of oil and natural gas. No other purchaser accounted for 10% or more of our oil and natural gas revenue for the quarter ended September 30, 2011.

To reduce exposure to fluctuations in oil and natural gas prices, to achieve more predictable cash flow, and as required by our lenders, we periodically utilize various derivative strategies to manage the price received for a portion of our future oil and natural gas production. We have not established derivatives in excess of our expected production.

Our open derivative positions at September 30, 2011, consisting of put/call collars, sold put options, which limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold and bare purchased put options, also called bare floors as they provide a floor price without a corresponding ceiling, are shown in the following table:

	Crude Oil (Bbls)							Natural Gas (Mmbtu)						
	Collars							Collars						
					Put Options Sold									
	Floors		Ceilings					Floors		Ceilings		Bare Floors		
Year	Per Day	Price	Per Day	Price	Per Day	Price	Year	Per Day	Price	Per Day	Price	Per Day	Price
Q4 11	2,150	$ 80.00	2,150	$ 105.00	-	-	Q4 11	-	-	-	-	6,973	$ 4.17
Q1 12	2,000	$ 80.00	2,000	$ 105.00	1,000	$ 70.00	Q1 12	-	-	-	-	6,700	$ 4.35
Q2 12	2,000	$ 80.00	2,000	$ 105.00	1,000	$ 70.00	Q2 12	5,000	$ 4.00	5,000	$ 6.00	-	-
Q3 12	1,900	$ 92.63	1,900	$ 105.66	1,238	$ 70.00	Q3 12	5,000	$ 4.00	5,000	$ 6.00	-	-
Q4 12	1,750	$ 92.14	1,750	$ 104.83	1,138	$ 70.00	Q4 12	-	-	-	-	-	-
Q1 13	1,800	$ 95.28	1,800	$ 101.39	1,450	$ 70.00	Q1 13	-	-	-	-	-	-
Q2 13	1,650	$ 95.00	1,650	$ 99.93	1,325	$ 70.00	Q2 13	-	-	-	-	-	-
Q3 13	1,600	$ 95.00	1,600	$ 99.94	-	-	Q3 13	-	-	-	-	-	-
Q4 13	1,550	$ 95.00	1,550	$ 99.71	-	-	Q4 13	-	-	-	-	-	-
Q1 14	1,600	$ 95.00	1,600	$ 100.03	1,600	$ 70.00	Q1 14	-	-	-	-	-	-
Q2 14	1,500	$ 95.00	1,500	$ 99.13	1,500	$ 70.00	Q2 14	-	-	-	-	-	-

Based on September 30, 2011, NYMEX forward curves of natural gas and crude oil futures prices, adjusted for volatility by 170 basis points, we would expect to receive future cash payments of $13.2 million under our natural gas and crude oil derivative arrangements as they mature. If future prices of natural gas and crude oil were to decline by 10%, we would expect to receive future cash payments under our natural gas and crude oil derivative arrangements of

$23.5 million, and if future prices were to increase by 10%, we would expect to receive future cash payments of $2.8 million.

ITEM 4 CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act) as of September 30, 2011. On the basis of this review, our management,

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including our principal executive officer and principal financial officer, concluded that our disclosure controls and procedures are designed, and are effective, to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, in a manner that allows timely decisions regarding required disclosure.

We did not effect any change in our internal controls over financial reporting during the quarter ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

The description of our plans and expectations set forth herein, including expected capital expenditures and acquisitions, are forward-looking statements made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These plans and expectations involve a number of risks and uncertainties. Important factors that could cause actual capital expenditures, acquisition activity or our performance to differ materially from the plans and expectations include, without limitation, our ability to satisfy the financial covenants of our outstanding debt instruments and to raise additional capital; our ability to manage our business successfully and to compete effectively in our business against competitors with greater financial, marketing and other resources; and adverse regulatory changes. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to update or revise these forward-looking statements to reflect events or circumstances after the date hereof including, without limitation, changes in our business strategy or expected capital expenditures, or to reflect the occurrence of unanticipated events.

PART II OTHER INFORMATION

ITEM 1 LEGAL PROCEEDINGS

Reference is made to Part I, Item 3, Legal Proceedings, in our annual report on Form 10-K for the year ended December 31, 2010 and Part II, Item 1, Legal Proceedings, in our quarterly report on Form 10-Q for the quarter ended June 30, 2011, for a discussion of pending legal proceedings to which we are a party.

ITEM 1A RISK FACTORS

Reference is made to Part I, Item 1A, Risk Factors, in our annual report on Form 10-K for the year ended December 31, 2010 and Part II, Item 1A, Risk Factors, in our quarterly report on form 10-Q for the quarter ended June 30, 2011, for a discussion of the risk factors which could materially affect our business, financial condition or future results.

ITEM 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3 DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4 [RESERVED]

ITEM 5 OTHER INFORMATION

None.

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ITEM 6 EXHIBITS

Exhibit	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of the Registrant.	(1) [3.1]
3.2	Amended and Restated Bylaws of the Registrant.	(8) [3.2]
10.1	Form of Registration Rights Agreement among the Registrant and the Initial Stockholders.	(2) [10.9]
10.1.1	Amendment to Registration Rights Agreement among this Registrant and the Founders dated May 8, 2006.	(1) [10.9.1]
10.2	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006.*	(1) [10.15]
10.2.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006.*	(5) [10.1]
10.2.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008.*	(10) [10.6.2]
10.2.3	Third Amendment to Employment Agreement of Larry E. Lee, dated December 30, 2008.*	(13) [10.6.3]
10.2.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009.*	(14) [10.6.4]
10.2.5	Fifth Amendment to Employment Agreement of Larry E. Lee dated March 17, 2010.*	(17) [10.6.5]
10.2.6	Sixth Amendment to Employment Agreement of Larry E. Lee dated March 8, 2011.*	(21) [10.2.6]
10.4	Registration Rights Agreement among Registrant and the investors signatory thereto dated May 8, 2006.	(1) [10.17]
10.5	Form of Registration Rights Agreement among the Registrant and the Investors party thereto.	(3) [10.17]
10.6	Agreement between RAM and Shell Trading-US dated February 1, 2006.	(1) [10.22]
10.7	Agreement between RAM and Targa dated January 30, 1998.	(1) [10.23]
10.7.1	Amendment to Agreement between RAM Energy and Targa dated effective as of April 1, 2006, filed as an exhibit to Registrant s Form 8-K dated June 5, 2006, and incorporated by reference herein.	(6) [10.23.1]
10.8	Long-Term Incentive Plan of the Registrant. Included as Annex C of the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006, and incorporated by reference herein.*	(4) [Annex C]

10.8.1	First Amendment to RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 8, 2008.*	(11) [Exhibit A]
10.8.2	Second Amendment to RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 3, 2010.*	(18) [10.8.2]
10.9	Deferred Bonus Compensation Plan of RAM Energy, Inc. dated as of April 21, 2004.*	(7) [10.14]
10.10	Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(9) [10.1]

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Exhibit	Description	Method of Filing
10.10.1	First Amendment to Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(15)[10.17.1]
10.10.2	Second Amendment to Loan Agreement dated November 29, 2007, by and between RAM Energy Resources, Inc., as Borrower, and Guggenheim Corporate Funding, LLC, as the Arranger and Administrative Agent, Wells Fargo Foothill, Inc., as the Documentation Agent and WestLB AG, New York Branch and CIT Capital USA Inc., as the Co-Syndication Agents, and the financial institutions named therein as the Lenders.	(16)[10.17.2]
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10.16	Equity Distribution Agreement, dated March 17, 2011.	(23)[1.1]
31.1	Rule 13(A) 14(A) Certification of our Principal Executive Officer.	**
31.2	Rule 13(A) 14(A) Certification of our Principal Financial Officer.	**
32.1	Section 1350 Certification of our Principal Executive Officer.	**
32.2	Section 1350 Certification of our Principal Financial Officer.	**
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101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	***
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* Management contract or compensatory plan or arrangement.

** Filed herewith.

*** Furnished with this report. In accordance with Rule 406T of Regulation S-T, the information in these exhibits shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such filing.

(1) Filed as an exhibit to the Registrant s Current Report on Form 8-K filed on May 12, 2006, as the exhibit number indicated in brackets and incorporated by reference herein.

(2) Filed as an exhibit to the Registrant s Registration Statement on Form S-1 (SEC File No. 333-113583) as the exhibit number indicated in brackets and incorporated by reference herein.

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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 hereunto duly authorized.

RAM ENERGY RESOURCES, INC.

November 7, 2011	By:	/s/ Larry E. Lee
	Name:	Larry E. Lee
	Title:	Chairman, President and Chief Executive Officer
November 7, 2011	By:	/s/ G. Les Austin
	Name:	G. Les Austin
	Title:	Senior Vice President, Chief Operating Officer and Chief Financial Officer

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INDEX TO EXHIBITS

Exhibit	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of the Registrant.	(1) [3.1]
3.2	Amended and Restated Bylaws of the Registrant.	(8) [3.2]
10.1	Form of Registration Rights Agreement among the Registrant and the Initial Stockholders.	(2) [10.9]
10.1.1	Amendment to Registration Rights Agreement among this Registrant and the Founders dated May 8, 2006.	(1) [10.9.1]
10.2	Employment Agreement between Registrant and Larry E. Lee dated May 8, 2006.*	(1) [10.15]
10.2.1	First Amendment to Employment Agreement between Registrant and Larry E. Lee dated October 18, 2006.*	(5) [10.1]
10.2.2	Second Amendment to Employment Agreement of Larry E. Lee dated February 25, 2008.*	(10) [10.6.2]
10.2.3	Third Amendment to Employment Agreement of Larry E. Lee, dated December 30, 2008.*	(13) [10.6.3]
10.2.4	Fourth Amendment to Employment Agreement of Larry E. Lee dated March 24, 2009.*	(14) [10.6.4]
10.2.5	Fifth Amendment to Employment Agreement of Larry E. Lee dated March 17, 2010.*	(17) [10.6.5]
10.2.6	Sixth Amendment to Employment Agreement of Larry E. Lee dated March 8, 2011.*	(21) [10.2.6]
10.4	Registration Rights Agreement among Registrant and the investors signatory thereto dated May 8, 2006.	(1) [10.17]
10.5	Form of Registration Rights Agreement among the Registrant and the Investors party thereto.	(3) [10.17]
10.6	Agreement between RAM and Shell Trading-US dated February 1, 2006.	(1) [10.22]
10.7	Agreement between RAM and Targa dated January 30, 1998.	(1) [10.23]
10.7.1	Amendment to Agreement between RAM Energy and Targa dated effective as of April 1, 2006, filed as an exhibit to Registrant s Form 8-K dated June 5, 2006, and incorporated by reference herein.	(6) [10.23.1]
10.8	Long-Term Incentive Plan of the Registrant. Included as Annex C of the Registrant s Definitive Proxy Statement (No. 000-50682), dated April 12, 2006, and incorporated by reference herein.*	(4) [Annex C]

10.8.1	First Amendment to RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 8, 2008.*	(11) [Exhibit A]
10.8.2	Second Amendment to RAM Energy Resources, Inc. 2006 Long-Term Incentive Plan effective May 3, 2010.*	(18) [10.8.2]
10.9	Deferred Bonus Compensation Plan of RAM Energy, Inc. dated as of April 21, 2004.*	(7) [10.14]
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