CRIMSON EXPLORATION INC.
Form 10-Q
November 07, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

OR

( ) 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 001-12108

CRIMSON EXPLORATION INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation)	20-3037840 (IRS Employer Identification No.)
717 Texas Avenue, Suite 2900 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

(713) 236-7400
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding twelve months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer x	Non-accelerated filer o	Smaller reporting company o
		(Do not check if smaller reporting company)	

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

On October 31, 2012, there were 46,063,417 shares outstanding of the registrant's Common Stock, par value $0.001.

FORM 10-Q

CRIMSON EXPLORATION INC.

FOR THE QUARTER ENDED SEPTEMBER 30, 2012

Table of Contents

2

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

	September 30, 2012 (unaudited)	December 31, 2011
CURRENT ASSETS		
Cash and cash equivalents	$—	$—
Accounts receivable, net of allowance of $547,184 and $579,143 respectively	14,642,466	16,059,667
Prepaid expenses	603,891	473,616
Derivative instruments	1,992,532	4,538,897
Deferred tax asset, net	4,115,129	—
Total current assets	21,354,018	21,072,180
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	735,690,418	663,414,446
Other property and equipment	3,339,738	3,345,798
Accumulated depreciation, depletion and amortization	(312,982,134)	(269,978,945)
Total property and equipment, net	426,048,022	396,781,299
NONCURRENT ASSETS		
Deposits	34,743	34,743
Debt issuance cost	1,152,218	1,140,031
Derivative instruments	203,348	—
Deferred tax asset, net	14,509,413	17,297,621
Total noncurrent assets	15,899,722	18,472,395
TOTAL ASSETS	$463,301,762	$436,325,874
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$35,000,057	$49,539,258
Accrued liabilities	9,193,995	16,131,324
Asset retirement obligations	772,856	935,705
Derivative instruments	—	290,703
Deferred tax liability, net	—	189,146
Total current liabilities	44,966,908	67,086,136
NONCURRENT LIABILITIES		
Long-term debt	240,948,063	190,041,933
Asset retirement obligations	9,944,789	9,071,064
Other noncurrent liabilities	584,026	621,043
Total noncurrent liabilities	251,476,878	199,734,040

Total liabilities	296,443,786	266,820,176
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Common stock (par value $0.001; 200,000,000 shares authorized; 46,260,576 and 45,270,768 shares issued and 46,071,219 and 45,129,407 shares outstanding, respectively)	46,260	45,271
Additional paid-in capital	245,347,188	243,484,877
Retained deficit	(77,686,560)	(73,352,170)
Treasury stock (at cost, 189,357 and 141,361 shares, respectively)	(848,912)	(672,280)
Total stockholders' equity	166,857,976	169,505,698
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$463,301,762	$436,325,874

The Notes to the Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine months Ended September 30, 2012	Nine months Ended September 30, 2011
OPERATING REVENUES				
Crude oil sales	$22,265,178	$8,866,235	$60,663,558	$25,718,944
Natural gas sales	6,312,901	14,747,982	19,433,566	45,011,246
Natural gas liquids sales	2,192,377	5,299,854	7,883,922	15,470,606
Total operating revenues	30,770,456	28,914,071	87,981,046	86,200,796
OPERATING EXPENSES				
Lease operating expenses	3,318,057	912,698	11,558,488	9,600,620
Production and ad valorem taxes	1,806,631	1,615,539	726,375	5,454,014
Exploration expenses (credit)	(186,550)	573,697	163,041	954,906
Depreciation, depletion and amortization	14,273,884	13,445,305	43,411,828	41,311,873
Impairment and abandonment of oil and gas properties	850,980	4,810,708	2,333,521	14,220,733
General and administrative	4,722,057	4,473,022	14,019,234	12,700,744
Gain on sale of assets	—	—	(8,900)	—
Total operating expenses	24,785,059	25,830,969	72,203,587	84,242,890
INCOME FROM OPERATIONS	5,985,397	3,083,102	15,777,459	1,957,906
OTHER INCOME (EXPENSE)				
Interest expense, net of amount capitalized	(6,454,526)	(6,045,543)	(18,912,514)	(19,028,127)
Other income (expense) and financing costs	(106,801)	(252,611)	(453,088)	(1,407,490)
Unrealized (loss) gain on derivative instruments	(4,564,414)	4,222,523	(2,052,314)	2,059,233
Total other income (expense)	(11,125,741)	(2,075,631)	(21,417,916)	(18,376,384)
INCOME (LOSS) BEFORE INCOME TAXES	(5,140,344)	1,007,471	(5,640,457)	(16,418,478)
Income tax (expense) benefit	1,294,220	(480,871)	1,306,067	5,572,553
NET INCOME (LOSS)	$(3,846,124)	$526,600	$(4,334,390)	$(10,845,925)
NET INCOME (LOSS) PER SHARE				
Basic	$(0.09)	$0.01	$(0.10)	$(0.24)
Diluted	$(0.09)	$0.01	$(0.10)	$(0.24)
WEIGHTED AVERAGE SHARES OUTSTANDING				
Basic	44,208,471	45,121,172	44,106,956	45,084,200
Diluted	44,208,471	45,166,566	44,106,956	45,084,200

The Notes to the Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2012
(UNAUDITED)

	NUMBER OF SHARES OF COMMON STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED DEFICIT	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
BALANCE, DECEMBER 31, 2011	45,129,407	$45,271	$ 243,484,877	$(73,352,170)	$ (672,280)	$ 169,505,698
Current period net loss	—	—	—	(4,334,390)	—	(4,334,390)
Share-based compensation	989,808	989	1,862,311	—	—	1,863,300
Treasury stock	(47,996)	—	—	—	(176,632)	(176,632)
BALANCE, SEPTEMBER 30, 2012	46,071,219	$46,260	$ 245,347,188	$(77,686,560)	$ (848,912)	$ 166,857,976

The Notes to the Consolidated Financial Statements are an integral part of this statement.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	For The Nine months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(4,334,390)	$(10,845,925)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	43,411,828	41,311,873
Asset retirement obligations	(328,071)	(203,566)
Stock compensation expense	1,828,252	1,476,840
Amortization of financing costs and discounts	1,176,105	1,874,159
Deferred income taxes	(1,516,067)	(5,572,553)
Impairment and abandonment of oil and gas properties	2,333,521	14,220,733
Gain on sale of assets	(8,900)	—
Unrealized (gain) loss on derivative instruments	2,052,314	(2,059,233)
Changes in operating assets and liabilities:		
Decrease in accounts receivable, net	1,417,201	817,559
Increase in prepaid expenses	(130,275)	(58,618)
Increase (decrease) in accounts payable and accrued liabilities	(21,513,547)	9,761,291
Net cash provided by operating activities	24,387,971	50,722,560
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(74,365,124)	(60,600,958)
Acquisition of oil and gas properties	—	(940,586)
Proceeds from sale of assets	400,900	—
Net cash used in investing activities	(73,964,224)	(61,541,544)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on debt	(166,123,602)	(97,884,387)
Proceeds from debt	216,145,665	108,884,387
Debt issuance expenditures	(304,225)	(46,213)
Proceeds from issuance of common stock	35,047	29,912
Purchase of treasury stock	(176,632)	(164,715)
Net cash provided by financing activities	49,576,253	10,818,984
INCREASE IN CASH AND CASH EQUIVALENTS	—	—
CASH AND CASH EQUIVALENTS,		
Beginning of period	—	—
CASH AND CASH EQUIVALENTS,		
End of period	$—	$—
Cash paid for interest	$17,847,837	$18,789,508
Cash paid for income taxes	$210,000	$—

The Notes to the Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. ORGANIZATION AND NATURE OF OPERATIONS

Crimson Exploration Inc., together with its subsidiaries, ("Crimson", "we", "our", "us") is an independent energy company engaged in the exploitation, exploration, development and acquisition of crude oil and natural gas properties. We have historically focused our operations in the onshore U.S. Gulf Coast, Texas and Colorado regions, which are generally characterized by high rates of return in known, prolific producing trends. We have expanded our strategic focus to include longer reserve life resource plays in Southeast Texas (the Woodbine, Eagle Ford Shale and Georgetown oil plays), South Texas (the Eagle Ford Shale oil play) and East Texas (the Haynesville and Mid-Bossier gas plays and the James Lime gas/liquids play). We believe these plays provide significant long-term growth potential from multiple formations. Additionally, we have producing properties in the DJ Basin in Weld and Adams Counties Colorado, which we believe are prospective in the Niobrara Shale oil play. Our operating revenues are derived from crude oil, natural gas and natural gas liquids sales that are proceeds from the sale of crude oil, natural gas and natural gas liquids production and realization of associated commodity derivatives.

2. BASIS OF PRESENTATION

Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("U.S.") for interim financial information and with the instructions to Form 10-Q and Rule 8-03 of Regulation S-X. Accordingly, they do not include all of the information and notes required by U.S. generally accepted accounting principles ("GAAP") for complete annual financial statements. The accompanying consolidated financial statements at September 30, 2012 (unaudited) and December 31, 2011 and for the three and nine months ended September 30, 2012 (unaudited) and 2011 (unaudited) contain all normally recurring adjustments considered necessary for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the three and nine months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012.

These consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our Annual Report on Form 10-K and Amendment No. 1 on Form 10-K/A for the year ended December 31, 2011.

The accompanying consolidated financial statements include Crimson Exploration Inc. and its wholly-owned subsidiaries: Crimson Exploration Operating, Inc. and LTW Pipeline Co. All material intercompany transactions and balances are eliminated upon consolidation. Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation.

3. USE OF ESTIMATES

The preparation of the consolidated financial statements in conformity with GAAP 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 consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates included in the consolidated financial statements are: (1) crude oil, natural gas and natural gas liquids

revenues and reserves; (2) depreciation, depletion and amortization; (3) valuation allowances associated with income taxes and accounts receivables; (4) accrued assets and liabilities; (5) stock-based compensation; (6) asset retirement obligations; (7) valuation of derivative instruments and (8) impairment of oil and gas properties. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates. Actual results could differ from those estimates.

4. FAIR VALUE MEASUREMENTS

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

Cash and Cash Equivalents, Accounts Receivable and Accounts Payable. The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Derivative Instruments. Our derivative instruments consist of variable to fixed price commodity swaps, costless collars, put options and interest rate swaps. The fair value measurement of our unrealized commodity price and interest rate instruments were obtained from financial institutions and were reviewed by management using our hedge agreements and future commodity and interest rate curves. Differences between management's calculation and that of the financial institutions were evaluated for reasonableness. See Note 5 — "Derivative Instruments" for further information.

Impairments. We review oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we classify impairments of long-lived assets as a level 3 fair value measurement. See Note 6 — "Oil and Gas Properties" for further information.

Asset Retirement Obligations. The initial measurement of asset retirement obligations ("AROs") at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, plugging costs and reserve lives. Because these significant factors are typically not observable, we classify asset retirement obligations as a level 3 fair value measurement. See Note 7 — "Asset Retirement Obligations" for further information.

Debt. The fair value of floating-rate debt is estimated to be equivalent to the carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 8 — "Debt" for further information.

Accounting guidance has established a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. There have been no transfers between Level 1, Level 2 or Level 3 during the three and nine months ended September 30, 2012.

Fair value measurements for assets and liabilities related to our derivative instruments that are measured at fair value on a recurring basis was as follows at September 30, 2012:

	Total Carrying Value	Fair Value Measurements Using		
		Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$2,195,880	$—	$2,195,880	$—
Commodity price contracts - liabilities	—	—	—	—
Total	$2,195,880	$—	$2,195,880	$—

Fair value measurements for assets and liabilities related to our derivative instruments that are measured at fair value on a recurring basis was as follows at December 31, 2011:

	Total Carrying Value	Fair Value Measurements Using		
		Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts - assets	$4,538,897	$—	$4,538,897	$—
Commodity price contracts - liabilities	(290,703)	—	(290,703)	—
Total	$4,248,194	$—	$4,248,194	$—

At September 30, 2012 or December 31, 2011, we did not measure assets or liabilities at fair value on a non-recurring basis.

5. DERIVATIVE INSTRUMENTS

At the end of each reporting period, we record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded net assets for derivative instruments of $2.2 million and $4.2 million at September 30, 2012 and December 31, 2011, respectively. As a result of these agreements, we recorded non-cash unrealized losses for unsettled contracts of $2.1 million and gains of $2.1 million for the nine months ended September 30, 2012 and 2011, respectively. The estimated change in fair value of the derivatives is reported in other income (expense) as unrealized gain (loss) on derivative instruments. The realized gain (loss) on derivative instruments is included in crude oil, natural gas and natural gas liquids sales for our commodity price hedges and as an (increase) decrease in interest expense for our interest rate swaps. Our remaining interest rate swap terminated on May 8, 2011.

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our crude oil and natural gas production, to reduce our sensitivity to volatile commodity prices, and with respect to portions of our debt, to reduce our sensitivity to volatile interest rates. None of our derivative instruments are designated as cash flow or fair value hedges. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil, natural gas and natural gas liquids sales and limit the benefit of decreases in interest rates. Moreover, our derivative arrangements apply only to a portion of our production and our debt and provide only partial protection against declines in commodity prices and increases in interest rates, respectively. Such arrangements may expose us to risk

of financial loss in certain circumstances. We continuously reevaluate our hedging programs in light of changes in production, market conditions, commodity price forecasts, capital spending, interest rate forecasts and debt service requirements.

We use a mix of commodity swaps, put options, costless collars and interest rate swaps to accomplish our hedging strategy. Derivative assets and liabilities with the same counterparty, subject to contractual terms which provide for net settlement, are reported on a net basis on our consolidated balance sheets. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry, and specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. We believe our counterparty risk is low in part because of the offsetting relationship we have with each of our counterparties provided for in our senior credit agreement with Wells Fargo Bank, National Association ("Wells Fargo Bank"), as agent, and the lender parties thereto (the "Senior Credit Agreement") and various hedge contracts. See Note 4 — "Fair Value Measurements" for further information.

The following derivative contracts were in place at September 30, 2012:

Crude Oil		Volume/Month (3)	Price/Unit	Fair Value
Oct 2012-Dec 2012	Collar	5,100 Bbls	$80.00-$107.30 (1)	$ 2,227
Oct 2012-Dec 2012	Collar	5,000 Bbls	$85.00-$102.70 (1)	5,851
Oct 2012-Dec 2012	Collar	4,500 Bbls	$90.00-$110.46 (1)	30,213
Oct 2012-Dec 2012	Swap	10,000 Bbls	$114.85 (2)	108,213
Oct 2012-Dec 2012	Swap	6,000 Bbls	$98.05 (1)	95,676
Jan 2013-Dec 2013	Swap	14,000 Bbls	$101.25 (1)	1,267,453
Natural Gas				
Oct 2012-Dec 2012	Put	320,000 Mmbtu	$5.00	1,029,331
Oct 2012-Dec 2012	Collar	160,000 Mmbtu	$2.50-$3.55	(48,437)
Jan 2013-Dec 2013	Collar	75,000 Mmbtu	$3.00-$4.25	(136,630)
Jan 2013-Dec 2013	Collar	75,000 Mmbtu	$3.25-$4.00	(158,017)
		Total net fair value of derivative instruments		$ 2,195,880

(1) Commodity derivative based on West Texas Intermediate crude oil
(2) Commodity derivative based on Brent crude oil
(3) Average volume per month for the remaining contract term

In October 2012, we entered into crude oil swaps for 9,000 Bbl/month for calendar year 2013 at $109.13 per barrel (Brent) and for 7,500 Bbl/month for calendar year 2014 at $102.10 per barrel (Brent). We also entered into natural gas collars for 42,500 Mmbtu/month for calendar years 2013 and 2014 with a $3.75 put price and a $4.60 call price and for 42,500 Mmbtu/month for calendar years 2013 and 2014 with a $3.50 put price and a $5.00 call price. These new hedges are part of our ongoing hedging strategy.

The following table details the effect of derivative contracts on the Consolidated Statements of Operations for the three and nine months ended September 30, 2012 and 2011, respectively:

Contract Type	Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Recognized in Income			
		Three months ended September 30,		Nine months ended September 30,	
		2012	2011	2012	2011
Crude oil contracts	Crude oil sales	$ 332,880	$ (613,143)	$ 757,643	$ (2,725,398)
Natural gas contracts	Natural gas sales	1,444,880	2,637,433	4,971,060	7,748,355
Natural gas liquids contracts	Natural gas liquids sales	—	(110,817)	—	(204,292)
Interest rate contracts	Interest expense	—	—	—	(1,410,764)
	Realized gain	$ 1,777,760	$ 1,913,473	$ 5,728,703	$ 3,407,901
Crude oil contracts	Unrealized (loss) gain on derivative instruments	$ (2,573,032)	$ 4,146,070	$ 1,619,783	$ 4,955,848
Natural gas contracts	Unrealized (loss) gain on derivative instruments	(1,991,382)	(52,682)	(3,672,097)	(4,204,047)
Natural gas liquids contracts	Unrealized (loss) gain on derivative instruments	—	129,135	—	(85,308)
Interest rate contracts	Unrealized (loss) gain on derivative instruments	—	—	—	1,392,740
	Unrealized gain (loss)	$ (4,564,414)	$ 4,222,523	$ (2,052,314)	$ 2,059,233

6. OIL AND GAS PROPERTIES

The following table sets forth the composition of impairment and abandonment expenses:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Impairment and abandonment of proved properties	$—	$—	$—	$—
Impairment and abandonment of unproved properties	850,980	4,810,708	2,333,521	14,220,733
	$850,980	$4,810,708	$2,333,521	$14,220,733

2012 Asset Impairments. Non-cash impairments of unproved properties were related to the ratable amortization of individually insignificant acreage positions. There were no impairments or abandonments of proved properties.

2011 Asset Impairments. Non-cash impairments of unproved properties for the nine months ended September 30 included $12.2 million related to our East Texas acreage and $2.0 million related to individually insignificant acreage. There were no impairments or abandonments of proved properties.

7. ASSET RETIREMENT OBLIGATIONS

We estimate the fair values of AROs based on historical experience of plug and abandonment costs by field and, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used and inflation rates.

The following table sets forth the composition of asset retirement obligations:

Beginning January 1, 2012 liability	$10,006,769
Accretion expense	377,169
Liabilities incurred	376,970
Liabilities settled	(830,298)
Revisions	787,035
Ending September 30, 2012 liability	$10,717,645

8. DEBT

We maintain a Senior Credit Agreement that matures on May 31, 2015. The borrowing base, reaffirmed at $100 million on November 1, 2012, is based on our current proved crude oil and natural gas reserves and is subject to semi-annual redeterminations, although our lenders may elect to make one additional unscheduled redetermination between scheduled redetermination dates. The next scheduled borrowing base redetermination date under our Senior Credit Agreement is May 1, 2013. The credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit. As of September 30, 2012, we had $71.1 million outstanding, with remaining availability of $28.9 million under our Senior Credit Agreement.

Advances under our Senior Credit Agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender's "prime rate" and the Federal Funds rate. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR market are quoted for the maturity selected. The applicable margin ranges between 1.75% and 2.75%, for LIBOR loans, and between 0.75% and 1.75%, for base rate loans. The specific applicable interest margin is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and nine months may be selected. The commitment fee payable on the unused portion of our borrowing base is between 0.375% and 0.500%, depending on the borrowing base utilization.

We also maintain a second lien credit agreement, dated December 27, 2010 with Barclays Bank Plc, as agent, and the lender parties thereto, including an affiliate of OCM GW Holdings, LLC ("Oaktree Holdings"), our largest stockholder (the "Second Lien Credit Agreement") which provides for a term loan made to us in a single draw in an aggregate principal amount of $175.0 million that matures on December 27, 2015. As of September 30, 2012, we had a principal amount of $175.0 million outstanding, with a discount of $5.1 million using the estimated market value interest rate at the time of issuance, for a net reported balance of $169.9 million.

Advances under our Second Lien Credit Agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the greatest of (i) 4.00% per annum, (ii) the "prime rate", (iii) the Federal Funds Effective Rate plus ½ of 1% and (iv) the LIBOR rate for a one month interest period plus 1.00%. The applicable margin for base rate loans is 8.50%. The interest rate on the LIBOR loans fluctuates based upon the higher of (i) 3.0% per annum and (ii) the LIBOR rate per annum. The applicable margin for LIBOR loans is 9.50%.

The Senior Credit Agreement and the Second Lien Credit Agreement (the "Credit Agreements") are secured by liens on substantially all of our assets, as well as security interests in the stock of our subsidiaries. The liens securing the Second Lien Credit Agreement are junior to those securing the Senior Credit Agreement. Interest is payable under the Credit Agreements as interim borrowings mature.

The Credit Agreements include usual and customary affirmative and negative covenants for credit facilities of their respective types and sizes, including, among others, limitations on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business, as well as events of default. Negative financial covenants in the Credit Agreements include those requiring us to maintain (i) a ratio of current assets (including borrowing base availability and excluding derivative instruments) to current liabilities (excluding current portion of long-term debt and derivative instruments) of at least 1.0 to 1.0, (ii) a ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters not greater than 3.50 to 1.00, (iii) a ratio of Adjusted EBITDAX to cash interest expense for any four trailing fiscal quarters not less than 2.75 to 1.00, and (iv) a ratio of the sum of (a) the aggregate outstanding principal amount borrowed under our Senior Credit Agreement plus (b) the aggregate face amount of all outstanding letters of credit, to EBITDAX for the trailing four fiscal quarters not greater than 2.25 to 1.00. EBITDAX represents net income (loss) before net interest expense, income taxes, and depreciation, depletion, amortization and exploration expenses. Adjusted EBITDAX, as defined in our credit agreements, represents EBITDAX as further adjusted for (i) unrealized gain or loss on derivative instruments, (ii) non-cash share-based compensation charges, (iii) impaired assets, (iv) other financing costs and (v) gains or losses on the disposition of assets. At September 30, 2012, we were in compliance with the aforementioned financial covenants.

9. LEGAL PROCEEDINGS

From time to time, we are involved in litigation relating to claims arising out of our properties or operations or from disputes with vendors in the normal course of business, including the matter discussed below.

In September 2012, we were named as defendant in a lawsuit filed in state district court for Harris County, Texas, involving a title dispute regarding a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County, Texas. The plaintiff has alleged that, based on the interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid. We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained mineral interests thereunder. The plaintiff alleges damages in excess of $6.0 million, which is based on prior payments received on its undisputed 1/16th mineral interest. This case is in its early stages and we are assessing the plaintiff's claims and issues associated therewith, but we intend to vigorously defend this lawsuit. We believe, if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit. We do not believe this suit will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

See Item 3 of our Annual Report on Form 10-K for the year ended December 31, 2011 for a description of other legal proceedings to which we are subject.

10. STOCKHOLDERS' EQUITY

In the nine months ended September 30, 2012, 370,935 shares of restricted Common Stock vested, of which 47,996 shares were withheld by us to satisfy the employees' tax liability resulting from the vesting of these shares, with the remaining shares being distributed to the employees and directors. During the nine months we also had 33,488 unvested shares of restricted Common Stock forfeited due to employee terminations. We issued 14,417 shares pursuant to stock option exercises. Discretionary grants of

954,000 shares of unvested restricted Common Stock were made to our employees during the nine months ended September 30, 2012 as incentive-based equity compensation under the 2005 Stock Incentive Plan. We also granted 54,879 shares of restricted Common Stock to three members of our board of directors as regular compensation pursuant to the Director Compensation Plan.

In the nine months ended September 30, 2011, 334,831 shares of restricted Common Stock vested, of which 41,402 shares were withheld by us to satisfy the employees' tax liability resulting from the vesting of these shares, with the remaining shares being distributed to the employees and directors. During the nine months we also had 164,703 unvested shares of restricted Common Stock forfeited due to employee terminations. We issued 12,463 shares pursuant to stock option exercises. Discretionary grants of 431,725 shares of unvested restricted Common Stock were made to our employees during the nine months as incentive-based equity compensation under the 2005 Stock Incentive Plan. We also granted 39,267 shares of restricted Common Stock to three members of our board of directors as regular compensation pursuant to the Director Compensation Plan.

11. INCOME TAXES

Income tax benefit for the nine months ended September 30, 2012 was approximately $1.3 million compared to $5.6 million for the nine months ended September 30, 2011. The quarterly income tax provision is based on our estimate of the effective tax rate expected to be applicable for the full year. Based upon our projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of our net operating loss carryforwards to reduce future income tax obligations. In the third quarter of 2012, we paid $0.2 million in state income taxes related to 2011 Texas margin tax.

12. RECENT ACCOUNTING PRONOUNCEMENTS

Accounting Standards Not Yet Adopted

In December 2011, the FASB issued Accounting Standards Update No. 2011—11 "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities". This accounting update requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The accounting update is effective for interim and annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

Further, we are closely monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2012 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

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

Forward-looking Statements

The following discussion should be read in conjunction with the consolidated financial statements and the notes thereto included in this Quarterly Report on Form 10-Q and with the consolidated financial statements, notes and management's discussion and analysis reported on our Annual Report on Form 10-K for the year ended December 31, 2011. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties.

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- reserve potential;
- business strategy;
- technology;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of crude oil and natural gas properties;
- timing and amount of production of crude oil and natural gas;
- exploration prospects;
- wells to be drilled and drilling results, including with respect to our identified drilling locations;
- operating results and working capital;
- results of borrowing base redeterminations under our senior credit agreement; and
- future methods and types of financing.

We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. For a discussion on risk factors affecting our business, see the information in "ITEM 1A. Risk Factors" contained in our Annual Report filed on Form 10-K for the year ended December 31, 2011 and in this report, as filed with the Securities and Exchange Commission.

Overview

We are an independent energy company engaged in the, exploitation, exploration, development and acquisition of crude oil and natural gas properties. We have historically focused our operations in the onshore U.S. Gulf Coast, Texas and Colorado regions, which are generally characterized by high rates of return in known, prolific producing trends. We have expanded our strategic focus to include longer reserve life resource plays in Southeast Texas (the Woodbine, Eagle Ford Shale and Georgetown oil plays), South Texas (the Eagle Ford Shale oil play) and East Texas (the Haynesville and Mid-Bossier gas plays and the James Lime gas/liquids play). We believe these plays provide significant long-term growth potential from multiple formations. Additionally, we have producing properties in the DJ Basin in Weld and Adams Counties, Colorado, which we believe are prospective in the Niobrara Shale oil play.

Until we see improvement in natural gas prices, we will focus our drilling activity almost entirely on further developing our oil and liquids-rich assets.

15

Results of Operations

The following is a discussion of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our consolidated financial statements and the notes thereto included in this Quarterly Report on Form 10-Q.

Comparative results of operations for the periods indicated are discussed below.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Revenues

	Three months ended September 30, 2012	Three months ended September 30, 2011	Change	Percent Change
Operating revenues:	(in millions, except percentages)			
Crude oil sales	$22.3	$8.9	$13.4	150.6 %
Natural gas sales	6.3	14.7	(8.4)	-57.1 %
Natural gas liquids sales	2.2	5.3	(3.1)	-58.5 %
Operating revenues	$30.8	$28.9	$1.9	6.6 %

Crude Oil, Natural Gas and Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our commodity price hedging instruments, were $30.8 million for the third quarter of 2012 compared to $28.9 million for the third quarter of 2011. The increase primarily results from a more than 132% increase in higher value oil production, offset, in part, by decline in our natural gas production, and decreases in realized natural gas and natural gas liquids prices.

Production

	Three months ended September 30, 2012	Three months ended September 30, 2011	Change	Percent Change
Sales volumes:				
Crude oil (Bbl)	228,895	98,523	130,372	132.3%
Natural gas (Mcf)	1,768,778	2,948,021	(1,179,243)	-40.0%
Natural gas liquids (Bbl)	70,607	102,595	(31,988)	-31.2%
Natural gas equivalents (Mcfe)	3,565,790	4,154,729	(588,939)	-14.2%
% crude oil and natural gas liquids	50.4%	29.0%		73.8%

Quarterly production was approximately 3.6 Bcfe for the third quarter of 2012 compared to approximately 4.2 Bcfe for the third quarter of 2011. On a daily basis, we produced an average of 38,759 Mcfe for the third quarter of 2012 compared to an average of 45,160 Mcfe for the third quarter of 2011, a decrease in equivalent volumes due to our shift to drilling oil and liquids-rich wells in 2012 which have a lower equivalent producing rate, but have had higher value. The decrease in natural gas liquids production of 31% was primarily driven by our Catherine Henderson A-6 well in Liberty County, Texas, that was not producing since January 2012 due to mechanical problems and natural gas liquids processing constraints of a purchaser. The Catherine Henderson A-6 has been successfully sidetracked and the

processing constraints have been resolved by the purchaser increasing production at the end of the third quarter of 2012. In the third quarter of 2012, we have successfully transitioned from a 71% natural gas production profile in 2011 to a current profile of an approximate 50/50 balance between crude oil/natural gas liquids and natural gas.

Average Sales Prices

	Three months ended September 30, 2012	2011	Change	Percent Change
Average sales prices (before hedging):				
Crude oil (Bbl)	$95.82	$96.21	$(0.39)	-0.4%
Natural gas (Mcf)	2.75	4.11	(1.36)	-33.1%
Natural gas liquids (Bbl)	31.05	52.74	(21.69)	-41.1%
Natural gas equivalents (Mcfe)	8.13	6.50	1.63	25.1%

	Three months ended September 30, 2012	2011	Change	Percent Change
Average sales prices (after hedging):				
Crude oil (Bbl)	$97.27	$89.99	$7.28	8.1%
Natural gas (Mcf)	3.57	5.00	(1.43)	-28.6%
Natural gas liquids (Bbl)	31.05	51.66	(20.61)	-39.9%
Natural gas equivalents (Mcfe)	8.63	6.96	1.67	24.0%

Crude oil, natural gas and natural gas liquids prices are reported net of the realized effects of our hedging agreements. We realized gains of $0.3 million on our crude oil hedges and $1.4 million on our natural gas hedges in the third quarter of 2012, compared to realized losses of $0.7 million for crude oil and natural gas liquids hedges and gains of $2.6 million for natural gas hedges in the third quarter of 2011. The increase in average realized prices for 2012, on an equivalent unit basis, was primarily due to an increase in oil and natural gas liquids production as a percentage of our product mix.

Costs and Expenses

	Three months ended September 30, 2012	2011	Change	Percent Change
Selected operating expenses:	(in millions, except percentages)			
Lease operating expenses	$3.3	$0.9	$2.4	266.7%
Production and ad valorem taxes	1.8	1.6	0.2	12.5%
Exploration expenses (credit)	(0.2)	0.6	(0.8)	NM
General and administrative (1)	4.1	4.0	0.1	2.5%
Operating expenses (cash)	9.0	7.1	1.9	26.8%
Depreciation, depletion & amortization	14.3	13.4	0.9	6.7%
Share-based compensation (1)	0.7	0.5	0.2	40.0%
Selected operating expenses (2)	$24.0	$21.0	$3.0	14.3%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

NM = not meaningful

	Three months ended September 30, 2012	2011	Change	Percent Change
Selected operating expenses ($ per Mcfe):	(in millions, except percentages)			
Lease operating expenses	$0.93	$0.22	$0.71	322.7 %
Production and ad valorem taxes	0.51	0.39	0.12	30.8 %
Exploration expenses (credit)	(0.05)	0.14	(0.19)	NM
General and administrative (1)	1.14	0.95	0.19	20.0 %
Operating expenses (cash)	2.53	1.70	0.83	48.8 %
Depreciation, depletion & amortization	4.00	3.24	0.76	23.5 %
Share-based compensation (1)	0.18	0.13	0.05	38.5 %
Selected operating expenses (2)	$6.71	$5.07	$1.64	32.3 %

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

(2) Exclusive of impairments, abandonments and sales of assets.

NM = not meaningful

Lease Operating Expenses. Lease operating expenses for the third quarter of 2012 were $3.3 million ($0.93 per Mcfe) compared to $0.9 million ($0.22 per Mcfe) in the third quarter of 2011. Excluding the effect of a $2.3 million change in our accrual estimates in the third quarter of 2011, lease operating expenses for the third quarter of 2011 would have been $3.2 million, comparable to the third quarter of 2012.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the third quarter of 2012 were $1.8 million compared to $1.6 million for the third quarter of 2011, a slight increase primarily due to higher revenues in 2012.

18

Exploration Expenses (Credit). Exploration expenses were a credit of $0.2 million in the third quarter of 2012 compared to expense of $0.6 million for the third quarter of 2011. The decrease in exploration expenses was primarily due to positive differences between settled asset retirement obligations and actual expenses incurred in the third quarter of 2012 compared to the third quarter of 2011.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for the third quarter of 2012 was $14.3 million compared to $13.4 million for the third quarter of 2011, an increase due to a higher DD&A rate associated with our recently developed crude oil wells, offset in part by lower production.

Impairment and Abandonment of Oil and Gas Properties. Non-cash impairment and abandonment of oil and gas properties for the third quarter of 2012 was $0.9 million compared to $4.8 million for the third quarter of 2011. The 2011 impairment was primarily the result of expiring leases in the individually significant pool for East Texas.

General and Administrative ("G&A") Expenses. Total G&A expenses were $4.7 million ($1.32 per Mcfe) for the third quarter of 2012 compared to $4.5 million ($1.08 per Mcfe) for the third quarter of 2011. Included in G&A expense is non-cash stock expense of $0.7 million ($0.18 per Mcfe) and $0.5 million ($0.13 per Mcfe) in the third quarters of 2012 and 2011, respectively.

Interest Expense. Interest expense was $6.5 million for the third quarter of 2012 and $6.0 million for the third quarter of 2011. Total interest expense increased primarily due to increased borrowings under our senior credit agreement with Wells Fargo Bank, National Association ("Wells Fargo Bank"), as agent, and the lender parties thereto (the "Senior Credit Agreement").

Other Income (Expense) and Financing Costs. Other income and financing costs were $0.1 million for the third quarter of 2012 compared to $0.3 million for the third quarter of 2011. These amounts consist primarily of the amortization of capitalized costs associated with our credit facilities and commitment fees related to the undrawn availability under our Senior Credit Agreement.

Unrealized Gain (Loss) on Derivative Instruments. The non-cash unrealized loss on derivative instruments was $4.6 million for the third quarter of 2012 compared to a gain of $4.2 million for the third quarter of 2011. With the expiration of our interest rate swaps in May 2011, our remaining derivative instruments are commodity price based only. The unrealized gain or loss is the change in the mark-to-market exposure under our commodity price hedging contracts. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges and the forward price curve of the commodities hedged.

Income Tax. Net loss before income taxes was $5.1 million for the third quarter of 2012 compared to net income before income taxes of $1.0 million in the third quarter of 2011. We recorded an income tax benefit of $1.3 million for the third quarter of 2012, compared to income tax expense of $0.5 million for the third quarter of 2011.

Nine months Ended September 30, 2012 Compared to Nine months Ended September 30, 2011

Revenues

	Nine months ended September 30, 2012	2011	Change	Percent Change
Operating revenues:	(in millions, except percentages)			
Crude oil sales	$60.7	$25.7	$35.0	136.2%
Natural gas sales	19.4	45.0	(25.6)	-56.9%
Natural gas liquids sales	7.9	15.5	(7.6)	-49.0%
Operating revenues	$88.0	$86.2	$1.8	2.1%

Crude Oil, Natural Gas and Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our hedging instruments, were $88.0 million for the first nine months of 2012 compared to $86.2 million for the first nine months of 2011. Revenue from higher oil production was offset, in part, by lower natural gas production because of natural field declines, and realized natural gas and natural gas liquids prices.

Production

	Nine months ended September 30, 2012	2011	Change	Percent Change
Sales volumes:				
Crude oil (Bbl)	584,713	282,774	301,939	106.8%
Natural gas (Mcf)	5,933,989	9,234,785	(3,300,796)	-35.7%
Natural gas liquids (Bbl)	215,663	324,670	(109,007)	-33.6%
Natural gas equivalents (Mcfe)	10,736,245	12,879,449	(2,143,204)	-16.6%
% crude oil and natural gas liquids	44.7%	28.3%		58.0%

Production was approximately 10.7 Bcfe for the first nine months of 2012 compared to 12.9 Bcfe for the first nine months of 2011. On a daily basis, we produced an average of 39,183 Mcfe in the first nine months of 2012 compared to an average of 47,177 Mcfe in the first nine months of 2011, a decrease in equivalent volumes due to our shift to drilling lower equivalent producing rate, higher value, oil and liquids-rich wells in 2012, resulting in a corresponding decline in natural gas production. The decrease in natural gas liquids production of 34% was primarily driven by our Catherine Henderson A-6 well in Liberty County, Texas, that was not producing since January 2012 due to mechanical problems and natural gas liquids processing constraints of a purchaser. The Catherine Henderson A-6 has been successfully sidetracked and the processing constraints have been resolved by the purchaser increasing production at the end of the third quarter of 2012.

Average Sales Prices

	Nine months ended September 30, 2012	2011	Change	Percent Change
Average sales prices (before hedging):				
Crude oil (Bbl)	$102.45	$100.59	$1.86	1.8%
Natural gas (Mcf)	2.44	4.04	(1.60)	-39.6%
Natural gas liquids (Bbl)	36.56	48.28	(11.72)	-24.3%
Natural gas equivalents (Mcfe)	7.66	6.32	1.34	21.2%

	Nine months ended September 30, 2012	2011	Change	Percent Change
Average sales prices (after hedging):				
Crude oil (Bbl)	$103.75	$90.95	$12.80	14.1%
Natural gas (Mcf)	3.27	4.87	(1.60)	-32.9%
Natural gas liquids (Bbl)	36.56	47.65	(11.09)	-23.3%
Natural gas equivalents (Mcfe)	8.19	6.69	1.50	22.4%

Crude oil, natural gas and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $0.8 million on our crude oil hedges and gains of $5.0 million on our natural gas hedges in the first nine months of 2012, compared to realized losses of $2.9 million on our crude oil and natural gas liquids hedges and gains of $7.7 million on our natural gas hedges in the first nine months of 2011. The increase in average realized prices for 2012, on an equivalent unit basis, was primarily due to an increase in oil/natural gas liquids production as a percentage of our product mix.

Costs and Expenses

	Nine months ended September 30, 2012	2011	Change	Percent Change
Selected operating expenses:	(in millions, except percentages)			
Lease operating expenses	$11.6	$9.6	$2.0	20.8%
Production and ad valorem taxes	0.7	5.5	(4.8)	-87.3%
Exploration expenses	0.2	1.0	(0.8)	-80.0%
General and administrative (1)	12.2	11.2	1.0	8.9%
Operating expenses	24.7	27.3	(2.6)	-9.5%
Depreciation, depletion & amortization	43.4	41.3	2.1	5.1%
Share-based compensation (1)	1.8	1.5	0.3	20.0%
Selected operating expenses (2)	$69.9	$70.1	$(0.2)	-0.3%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

	Nine months ended September 30, 2012	2011	Change	Percent Change
Selected operating expenses ($ per Mcfe):		(in millions, except percentages)		
Lease operating expenses	$1.08	$0.75	$0.33	44.0%
Production and ad valorem taxes	0.07	0.42	(0.35)	-83.3%
Exploration expenses	0.02	0.07	(0.05)	-71.4%
General and administrative (1)	1.14	0.87	0.27	31.0%
Operating expenses	2.31	2.11	0.20	9.5%
Depreciation, depletion & amortization	4.04	3.21	0.83	25.9%
Share-based compensation (1)	0.17	0.11	0.06	54.5%
Selected operating expenses (2)	$6.52	$5.43	$1.09	20.1%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.
(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

Lease Operating Expenses. Lease operating expenses for the first nine months of 2012 were $11.6 million ($1.08 per Mcfe) compared to $9.6 million ($0.75 per Mcfe) in the first nine months of 2011, an increase resulting from higher operating well count, higher cost environment and increased workover expenses. The increase on a per Mcfe basis is primarily due to the lower equivalent production volumes and higher lifting costs resulting from our shift to drilling oil and liquids-rich wells.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the first nine months of 2012 were $0.7 million compared to $5.5 million for the first nine months of 2011, a decrease primarily due to a $4.1 million severance tax refund from the State of Texas for certain 2007- 2012 allowed marketing cost deductions.

Exploration Expenses. Exploration expenses were $0.2 million in the first nine months of 2012 compared to $1.0 million for the first nine months of 2011, a decrease primarily due to positive differences between settled asset retirement obligations and actual expenses incurred in the first nine months of 2012 compared to the first nine months of 2011.

Depreciation, Depletion and Amortization (“DD&A”). DD&A expense for the first nine months of 2012 was $43.4 million compared to $41.3 million for the first nine months of 2011, an increase primarily due to a higher DD&A rate associated with our recently developed crude oil wells, offset in part by lower equivalent production.

Impairment and Abandonment of Oil and Gas Properties. Non-cash impairment and abandonment of oil and gas properties for the first nine months of 2012 was $2.3 million compared to $14.2 million for the first nine months of 2011. The 2011 impairment was primarily the result of expiring leases in the individually significant pool for East Texas.

General and Administrative (“G&A”) Expenses. Total G&A expenses were $14.0 million ($1.31 per Mcfe) for the first nine months of 2012 compared to $12.7 million ($0.99 per Mcfe) for the first nine months of 2011, which includes non-cash stock expense of $1.8 million ($0.17 per Mcfe) and $1.5 million ($0.11 per Mcfe) for the first nine months of 2012 and 2011, respectively. G&A expenses increased primarily due to higher facility costs.

22

Interest Expense. Interest expense was $18.9 million for the first nine months of 2012 compared to $19.0 million for the first nine months of 2011. Total interest expense remained flat primarily due to increased borrowings under our Senior Credit Agreement offset by the absence of interest rate hedge settlements in 2012. Capitalized interest expense for the first nine months of 2012 and 2011 was zero and approximately $0.2 million, respectively.

Other Income (Expense) and Financing Costs. Other income and financing costs were $0.5 million for the first nine months of 2012 compared with $1.4 million for the first nine months of 2011. These amounts consist primarily of the amortization of capitalized costs associated with our credit facilities and commitment fees related to the undrawn availability under our Senior Credit Agreement.

Unrealized Gain (Loss) on Derivative Instruments. The non-cash unrealized loss for the first nine months of 2012 was $2.1 million compared with a non-cash unrealized gain of $2.1 million for the first nine months of 2011. Unrealized gain or loss is the change in the mark-to-market exposure under our commodity price hedging contracts and our interest rate swaps during the period. Unrealized gain or loss will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities hedged.

Income Tax. Our net loss before taxes was $5.6 million for the first nine months of 2012 compared to $16.4 million for the first nine months of 2011. After adjusting for permanent tax differences, we recorded an income tax benefit of approximately $1.3 for the first nine months of 2012, compared to $5.6 million for the first nine months of 2011.

Liquidity and Capital Resources

Our primary cash requirements are for capital expenditures, working capital, operating expenses and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be borrowed under our Senior Credit Agreement. To the extent our cash requirements exceed our sources of liquidity, we will be required to fund our cash requirements through other means, such as through debt and equity financing activities or asset monetizations, or the curtailment of capital expenditures.

Liquidity and Cash Flow

The following table provides the components and changes in working capital as of September 30, 2012 and December 31, 2011.

	September 30, 2012	December 31, 2011	Change
Current assets		(in millions)	
Accounts receivable, net	$14.7	$ 16.1	$(1.4)
Prepaid expenses	0.6	0.5	0.1
Derivative instruments	2.0	4.5	(2.5)
Deferred tax asset, net	4.1	—	4.1
Total current assets	21.4	21.1	0.3
Current liabilities			
Accounts payable and accrued liabilities (1)	44.2	65.7	(21.5)
Asset retirement obligations	0.8	0.9	(0.1)
Derivative instruments	—	0.3	(0.3)
Deferred tax liability, net	—	0.2	(0.2)
Total current liabilities	45.0	67.1	(22.1)
Working capital (deficit)	$(23.6)	$ (46.0)	$22.4

(1) Reflects impact of reduced drilling activity in September 2012 compared to December 2011.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the nine months ended September 30, 2012 and 2011, respectively.

	Nine months ended September 30, 2012	2011
Financial Measures	(in millions)	
Net cash provided by operating activities	$24.4	$50.7
Net cash used in investing activities	(74.0)	(61.5)
Net cash provided by financing activities	49.6	10.8
Cash and cash equivalents	—	—

During the first nine months of 2012 the net cash provided by operating activities, before changes in working capital, increased by $4.4 million from $40.2 million for the first nine months of 2011, to $44.6 million for the first nine months of 2012, primarily due to lower severance taxes in the first nine months of 2012 due to the $4.1 million severance tax refund.

Net cash used in investing activities consists primarily of capital expenditures on oil and gas drilling projects.

Net cash provided by financing activities, which consists primarily of net borrowings/repayments on our Senior Credit Agreement, increased primarily due to temporary funding of our accelerated 2012 drilling activity and the reduction in the working capital deficit due to fewer rigs running in the third quarter of 2012.

See the Consolidated Statements of Cash Flows for further details.

Future Capital Requirements

Our future crude oil, natural gas and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by further exploiting our existing property base through drilling opportunities identified in our resource plays in South, Southeast and East Texas and Colorado and in our conventional inventory, with activity in any particular area to be a function of market and field economics. In the short term, due to the challenging natural gas environment, and the superior economics from oil production, we will focus the majority of our capital expenditures on the development of our South Texas and Southeast Texas oil/liquids project inventory.

The oil and gas industry has experienced a challenging natural gas price environment which has also impacted us with respect to proved natural gas reserves estimates. If natural gas prices do not improve in the fourth quarter of 2012, our proved undeveloped natural gas reserves in the East Texas Haynesville and Mid-Bossier Shale at December 31, 2012 will likely be revised downward or eliminated as not being economically producible under applicable unhedged historical SEC pricing. However, the impact of these revisions on the standardized measure of future net cash flows and net present value (discounted at 10% using an SEC pricing) of proved reserves at year-end 2012 could be slightly positive, since the standardized measure and discounted value (at 10%) of these reserves at year-end 2011 was slightly negative. If natural gas prices increase in future periods and the economies of dry gas projects improve, these undeveloped reserves could potentially be added back to our proven reserve estimates.

We are currently developing our 2013 budget, including our capital expenditures plan that will be focused primarily on our oil-rich acreage in the Woodbine formation in Madison and Grimes Counties, in our Southeast Texas region. We also may allocate some capital to additional Eagle Ford Shale wells, and possibly a Buda test well, in Zavala and Dimmit Counties in the South Texas region. The actual number of wells to be drilled and the amount of our 2013 capital expenditures will depend on market conditions, availability of capital and drilling and production results, and the amount ultimately to be spent during the year, and the projects pursued, will be monitored for appropriate revision, upward or downward, in light of these factors.

We will continue to monitor industry activity in the oil weighted Niobrara Shale in the DJ basin of Colorado and the liquids-rich James Lime play in East Texas. Planned drilling activity by large operators in and around our positions in both plays provides us with insight as to the future potential and strategy for optimizing value in each play prior to having to expend drilling capital. Results of the offset activity will determine our strategy and activity level in these plays in 2013; and given offset operator success, we may adjust our capital budget to capitalize on opportunities on our acreage positions.

We intend to continue to evaluate potential acquisition opportunities in our core areas to expand our presence in our South and Southeast Texas resource plays, to exploit our oil and liquids-rich positions and to continue to develop exploitation opportunities on our conventional properties where commodity price-justified. Acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise to exploit identified drilling opportunities, and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

We believe that our internally generated cash flow, combined with access to our revolving credit agreement, will be sufficient to meet the liquidity requirements necessary to fund our daily operations and planned capital development and to meet our debt service requirements through the end of 2013. We currently plan to initially limit our 2013 capital expenditures to our forecasted cash flow from operations

25

for the year; however, we do possess the capacity, through our revolving credit agreement, to increase and/or accelerate drilling on any particular area should we determine that market and project economics so warrant. The substantial majority of our planned capital expenditures are on acreage that is currently held by existing production, therefore, we also possess the flexibility of reducing our capital expenditures, if deemed appropriate. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit agreement in connection with a borrowing base redetermination. In addition, if any lender under our credit agreement is unable to fund their commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender's commitment under our credit agreement. In such case, we may be required to seek other sources of capital earlier than anticipated. Restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all.

We utilize commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We use a series of swaps, put options and costless collars to accomplish our commodity hedging position. We currently have 1.9 Bcfe of production hedged for 2012, consisting of 92 MBbl of crude oil hedges and 1.4 Bcf of natural gas hedges at average floor prices of $97.22/Bbl and $4.17/Mmbtu, respectively. We also have 4.5 Bcfe of equivalent production hedged for 2013, consisting of 276 MBbl of crude oil hedges and 2.8 Bcf of natural gas hedges at average floor prices of $104.33/Bbl and $3.31/Mmbtu, respectively. We also have 1.6 Bcfe of equivalent production hedged for 2014, consisting of 90 MBbl of crude oil hedges and 1.0 Bcf of natural gas hedges at an average floor prices of $102.10/Bbl and $3.63/Mmbtu, respectively.

Our capital resources are described in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" of our Annual Report on Form 10-K for the year ended December 31, 2011 and Note 8 — "Debt" of our Quarterly Report on Form 10-Q for the quarter ended September 30, 2012

Recent Accounting Pronouncements

In December 2011, the FASB issued Accounting Standards Update No. 2011—11 "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities". This accounting update requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The accounting update is effective for interim and annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

Further, we are closely monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2012 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are currently exposed to market risk primarily related to adverse changes in crude oil, natural gas and natural gas liquids prices. We use derivative instruments to manage our commodity price risk caused by fluctuating prices. We do not enter into derivative instruments for trading purposes. For information regarding our exposure to certain market risks, see Item 7A. "Quantitative and Qualitative Disclosure About Market Risk" in our 2011 Annual Report and Note 5 – Derivative Instruments included in Part I. Item 1. Financial Statements of this Form 10-Q.

Commodity Price Risk

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our crude oil, natural gas and natural gas liquids production, to reduce our sensitivity to volatile commodity prices. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of crude oil, natural gas and natural gas liquids. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial protection against declines in commodity prices. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our derivative hedging program in light of increases in production, market conditions, commodity price forecasts, capital spending and debt service requirements.

At September 30, 2012, we had entered into swaps, put options and costless collars related to future crude oil and natural gas sales with a net fair value of $2.2 million. A price increase of $1.00 per Bbl of crude oil would decrease the net fair value of our commodity derivatives by approximately $0.2 million. A price increase of $0.10 per MMBtu for natural gas would decrease the net fair value of our commodity derivatives by approximately $0.2 million.

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. In the past we have entered into, and may in the future enter into, interest rate swap agreements. Changes in interest rates affect the amount of interest we pay on borrowings under our Senior Credit Agreement and our Second Lien Credit Agreement. At September 30, 2012, we did not have any outstanding interest rate swap agreements. Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our Senior Credit Agreement would result in an increase of our interest expense by $0.7 million for a twelve month period, assuming current debt levels.

ITEM 4. CONTROLS AND PROCEDURES

Our President and Chief Executive Officer and our Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this Form 10-Q, that our disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, are effective to ensure that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that our disclosure controls and procedures are effective to ensure that information we are required to disclose in such reports is accumulated and communicated to management, including our President and Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

During the three months ended September 30, 2012, there have been no changes to our internal controls over financial reporting that materially affected, or is reasonably likely to materially affect, these controls.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are involved in litigation relating to claims arising out of our properties or operations or from disputes with vendors in the normal course of business, including the matter discussed below.

In September 2012, we were named as defendant in a lawsuit filed in state district court for Harris County, Texas, involving a title dispute regarding a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County, Texas. The plaintiff has alleged that, based on the interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid. We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained mineral interests thereunder. The plaintiff alleges damages in excess of $6.0 million, which is based on prior payments received on its undisputed 1/16th mineral interest. This case is in its early stages and we are assessing the plaintiff's claims and issues associated therewith, but we intend to vigorously defend this lawsuit. We believe, if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit. We do not believe this suit will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

See Item 3 of our Annual Report on Form 10-K for the year ended December 31, 2011 for a description of other legal proceedings to which we are subject.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2011, which could materially affect our business, financial condition or future results. The risks described in this report and in our previous filings with the Securities and Exchange Commission are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Final rules regulating air emissions from natural gas production could cause us to incur increased capital expenditures and operating costs, which could be significant.

On August 16, 2012, the U.S. Environmental Protection Agency (the "EPA") published final rules under the federal Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flowback emissions to a gathering line or be captured and combusted using a combustion device (e.g., flares) after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices,

29

after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

We withheld the following shares of Crimson Common Stock from employee stock distributions to satisfy tax withholding obligations related to restricted stock which vested during the third quarter of 2012. These shares may be deemed to be "issuer purchases" of shares that are required to be disclosed pursuant to this item.

Period	Total Number of Shares Purchased (1)	Average price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number (or Approximate Dollar Value) of Shares That May Be Purchased Under the Plan or Programs
August 1-31, 2012	3,306	$ 4.85	3,306	(1)
September 1-30, 2012	2,756	$ 4.43	2,756	(1)
Total	6,062		6,062	

(1) Shares were withheld from employees in satisfaction of certain tax withholding obligations due in connection with vesting of restricted grants of stock under our 2005 Stock Incentive Plan. Company policy and the 2005 Stock Incentive Plan provide for the withholding of shares to satisfy tax obligations.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Number	Description
3.1	Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on July 5, 2005)
3.2	

Bylaws of Crimson Exploration Inc. (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed on July 5, 2005)

30

Number	Description
3.3	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Appendix A to the Company's Definitive Information Statement on Schedule 14C filed on August 18, 2006)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed on July 5, 2005)
4.2	Shareholders Rights Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(e) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
4.3	Waiver, Consent and First Amendment to the Shareholders Rights Agreement, dated as of December 7, 2009, between Crimson Exploration Inc. and OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on December 10, 2009)
4.4	Registration Rights Agreement between Crimson Exploration Inc. and America Capital Energy corporation, dated as of December 22, 2010 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 28, 2010 File No. 001-12108)
*31.1	Certification of Chief Executive Officer pursuant to Exchange Rule13a-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer pursuant to Exchange Rule 13a-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certification of Chief Executive Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certification of Chief Financial Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Labels Linkbase Document

*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document
	*Filed herewith
	**Furnished herewith
	#Management contract or compensatory plan or arrangement

SIGNATURES

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

CRIMSON EXPLORATION INC.
(Registrant)

Date:	November 7, 2012	By:	/s/ Allan D. Keel Allan D. Keel President and Chief Executive Officer
Date:	November 7, 2012	By:	/s/ E. Joseph Grady E. Joseph Grady Senior Vice President and Chief Financial Officer