SARATOGA RESOURCES INC /TX
Form 10-Q
November 14, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2014

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 001-35241

SARATOGA RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Texas	76-0314489
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

3 Riverway, Suite 1810, Houston, Texas 77056
(Address of principal executive offices)(Zip Code)

(713) 458-1560
(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 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x   No ¨

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 x   No ¨

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

Large accelerated filer ¨   Accelerated filer ¨   Non-accelerated filer ¨   Smaller reporting company x

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x   No ¨

As of November 14, 2014, we had 30,986,601 shares of $0.001 par value Common Stock outstanding.

SARATOGA RESOURCES, INC.

FORM 10-Q

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PART I - FINANCIAL INFORMATION

ITEM 1

Financial Statements

SARATOGA RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,382,261	$ 32,547,380
Accounts receivable	7,117,084	6,758,572
Prepaid expenses and other	1,596,937	1,056,350
Other current asset	150,000	150,000
Total current assets	15,246,282	40,512,302
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	298,399,871	286,441,663
Other	1,031,779	892,694
	299,431,650	287,334,357
Less: Accumulated depreciation, depletion and amortization	(113,178,609)	(101,088,696)
Total property and equipment, net	186,253,041	186,245,661
Other assets, net	21,019,005	21,665,830
Total assets	$ 222,518,328	$ 248,423,793
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 3,821,718	$ 5,391,648
Revenue and severance tax payable	3,977,919	3,754,812
Accrued liabilities	8,679,128	9,807,935
Derivative liabilities short term	47,131	837,758
Short-term notes payable	824,909	338,512
Total current liabilities	17,350,805	20,130,665
Long-term liabilities:		
Asset retirement obligation	13,994,857	12,649,458
Long-term debt, net of unamortized discount of $1,158,092 and $1,603,016, respectively	178,641,908	178,196,984
Derivative liabilities	-	182,174

Total long-term liabilities		192,636,765		191,028,616
Commitment and contingencies (see notes)				
Stockholders' equity:				
Common stock, $0.001 par value; 100,000,000 shares authorized 30,986,601 and 30,946,601 shares issued and outstanding at September 30, 2014 and December 31, 2013, respectively		30,987		30,947
Additional paid-in capital		78,646,678		78,165,364
Accumulated other comprehensive loss		-		-
Retained deficit		(66,146,907)		(40,931,799)
Total stockholders' equity		12,530,758		37,264,512
Total liabilities and stockholders' equity	$	222,518,328	$	248,423,793

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

SARATOGA RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND OTHER COMPREHENSIVE LOSS
(Unaudited)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues:				
Oil and gas revenues	$ 15,948,797	$ 17,195,776	$ 41,672,505	$ 54,185,434
Oil and gas hedging	644,190	(717,378)	1,503,857	(226,541)
Other revenues	21,682	3,466	170,283	249,815
Total revenues	16,614,669	16,481,864	43,346,645	54,208,708
Operating Expense:				
Lease operating expense	6,642,635	5,490,268	18,439,907	15,293,422
Workover expense	1,750,760	848,094	4,050,528	2,277,226
Exploration expense	225,949	462,994	647,599	746,965
Loss on plugging and abandonment	-	727,039	-	727,039
Depreciation, depletion and amortization	4,839,858	4,919,418	12,089,913	15,790,454
Impairment expense	-	2,179,075	-	2,179,075
Accretion expense	448,466	638,097	1,345,399	1,914,291
General and administrative	2,401,158	2,365,501	7,456,116	6,804,243
Severance taxes	1,058,787	1,900,292	2,869,129	5,892,904
Arbitration loss	3,400,000	-	3,400,000	-
Total operating expenses	20,767,613	19,530,778	50,298,591	51,625,619
Operating income (loss)	(4,152,944)	(3,048,914)	(6,951,946)	2,583,089
Other income (expense):				
Interest income	(2,174)	8,548	31,174	27,008
Interest expense	(6,084,572)	(5,368,376)	(18,138,276)	(15,905,464)
Total other expense	(6,086,746)	(5,359,828)	(18,107,102)	(15,878,456)
Net loss before reorganization expense and income taxes	(10,239,690)	(8,408,742)	(25,059,048)	(13,295,367)
Reorganization expense	-	-	-	2,319
Net loss before income taxes	(10,239,690)	(8,408,742)	(25,059,048)	(13,297,686)
	33,795	(2,683,382)	156,060	(4,196,914)

Income tax expense (benefit)								
Net loss	$	(10,273,485)	$	(5,725,360)	$	(25,215,108)	$	(9,100,772)
Other comprehensive loss								
Unrealized gain (loss) on derivative instruments		12,451		(666,614)		-		192,115
Total comprehensive loss	$	(10,261,034)	$	(6,391,974)	$	(25,215,108)	$	(8,908,657)
Net loss per share:								
Basic	$	(0.33)	$	(0.19)	$	(0.81)	$	(0.29)
Diluted	$	(0.33)	$	(0.19)	$	(0.81)	$	(0.29)
Weighted average number of common shares outstanding:								
Basic		30,986,601		30,945,242		30,961,106		30,927,802
Diluted		30,986,601		30,945,242		30,961,106		30,927,802

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

SARATOGA RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Nine Months Ended September 30, 2014	2013
Cash flows from operating activities:		
Net loss	$ (25,215,108)	$ (9,100,772)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	12,089,913	15,790,454
Impairment expense	-	2,179,075
Accretion expense	1,345,399	1,914,291
Amortization of debt issuance costs	1,845,865	1,006,240
Amortization of debt discount	444,924	366,709
Stock-based compensation	420,154	769,427
Loss on plugging and abandonment	-	727,039
Deferred tax benefit	-	(4,295,153)
Unrealized gain on hedges	(1,593,301)	(290,668)
Changes in operating assets and liabilities:		
Accounts receivable	(358,512)	4,204,469
Prepaids and other	1,066,692	1,124,277
Accounts payable	(163,841)	(3,619,119)
Revenue and severance tax payable	223,107	(1,483,844)
Payments to settle asset retirement obligations	-	(1,247,239)
Accrued liabilities	(558,992)	(4,581,395)
Net cash (used in) provided by operating activities	(10,453,700)	3,463,791
Cash flows from investing activities:		
Additions to oil and gas property	(13,313,612)	(23,905,494)
Additions to other property and equipment	(139,085)	(94,250)
Other assets	(932,111)	(1,151,793)
Net cash used in investing activities	(14,384,808)	(25,151,537)
Cash flows from financing activities:		
Proceeds from issuance of common stock	61,200	23,795
Repayment of short-term notes payable	(1,120,882)	(1,050,384)
Debt issuance costs of long term debt	(266,929)	-
Net cash used in financing activities	(1,326,611)	(1,026,589)
Net decrease in cash and cash equivalents	(26,165,119)	(22,714,335)
Cash and cash equivalents - beginning of period	32,547,380	32,302,313
Cash and cash equivalents - end of period	$ 6,382,261	$ 9,587,978
Supplemental disclosures of cash flow information:		
Cash paid for income taxes	$ 156,060	$ 98,239
Cash paid for interest	19,749,428	19,082,534

Non-cash investing and financing activities:				
Unrealized gain (loss) on derivative instruments	$	-	$	192,115
Accounts payable for oil and gas additions		(1,406,089)		4,244,015
Accrued liabilities for oil and gas additions		50,685		435,998
Prepaid insurance financed with debt		1,607,279		1,523,305

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

SARATOGA RESOURCES, INC.

Notes to Consolidated Financial Statements

September 30, 2014

(Unaudited)

NOTE 1 ORGANIZATION AND BASIS OF PRESENTATION

Organization

Saratoga Resources, Inc. (Saratoga or the Company) is an independent oil and natural gas company engaged in the acquisition, development, exploitation and production of natural gas and crude oil properties.

Financial Statements Presented

The accompanying unaudited financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial information and with the instructions to Form 10-Q. They do not include all of the information and footnotes required by accounting principles generally accepted in the United States of America for a complete financial presentation. In the opinion of management, all adjustments, consisting only of normal recurring adjustments, considered necessary for a fair presentation, have been included in the accompanying unaudited financial statements. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

The Company utilizes the successful efforts method of accounting for oil and gas producing activities.

These financial statements should be read in conjunction with the financial statements and footnotes which are included as part of the Company s Form 10-K for the year ended December 31, 2013.

Reclassifications of Prior Period Statements

Certain reclassifications of prior period consolidated financial statement balances have been made to conform to current reporting practices.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash, cash equivalents and any marketable securities. The Company had cash deposits of approximately $6.1 million in excess of FDIC insured limits at the period end. The Company has not experienced any losses on its deposits of cash and cash equivalents.

NOTE 2 OIL AND GAS PROPERTIES

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The factors used to determine fair value include, but are not limited to, estimates of proved 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.

During the nine months ended September 30, 2014, we did not recognize any impairment expense. During the nine months ended September 30, 2013 we recognized $2,179,075 in impairment expense related to the loss of a lease in Louisiana.

NOTE 3 DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Objective and Strategies for Using Commodity Derivative Instruments

The Company periodically enters into commodity derivative instruments, primarily fixed price swaps, to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company. The fixed price swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price. We would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price. The amount payable by us, if the floating price is above the fixed price, is the product of the notional quantity per calculation period and the excess of the floating price over the fixed price with respect to each calculation period. The amount payable by the counterparty, if the floating price is below the fixed price, is the product of the notional quantity per calculation period and the excess of the fixed price over the floating price with respect to each calculation period. We receive proceeds for the sale of crude oil call options which carry a strike price. The call option, when combined with the Company s long production position, represents a covered call and creates a ceiling, at the strike price, on the price to be received during the covered period for the related production.

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits from future increases in commodity prices.

See Note 4 Fair Value Measurements for a discussion of the methods and assumptions used to estimate the fair values of our commodity derivative instruments.

The Company utilizes hedge accounting for our commodity derivative instruments, which are designated as cash flow hedges.

Counterparty Credit Risk

Commodity derivative instruments expose us to counterparty credit risk. Our commodity derivative instruments are with one and two counterparties at September 30, 2014 and December 31, 2013, respectively. We monitor and manage our level of financial exposure with respect to the counterparties we use. Our commodity derivative contracts are executed under master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election.

We monitor the creditworthiness of our commodity derivatives counterparties. However, we are not able to predict sudden changes in counterparties creditworthiness. In addition, even if such changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk.

As of September 30, 2014, the Company had the following hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Strike Price	Premium	Total Bbls
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	45,500
						45,500

The following table presents the fair value of the Company s commodity derivative instruments at September 30, 2014 and December 31, 2013:

Description	September 30, 2014	December 31, 2013
Current liabilities:		
Commodity derivatives	$ 47,131	$ 837,758
	$ 47,131	$ 837,758
Long-term liabilities:		
Commodity derivatives	$ -	$ 182,174
	$ -	$ 182,174

The following tables present the effect of commodity derivative instruments on our consolidated statements of operations and comprehensive income (loss) for the three and nine months ended September 30, 2014 and 2013:

	For the Three months Ended September 30,		For the Nine months Ended September 30,	
Description	**2014**	**2013**	**2014**	**2013**
Unrealized mark-to-market gain (loss)	$ 533,782	$ (592,063)	$ 1,593,301	$ 290,667
Realized gain (loss) on settlements	110,408	(125,315)	(89,444)	(517,208)
Total gain (loss) on commodity derivative instruments	$ 644,190	$ (717,378)	$ 1,503,857	$ (226,541)

	For the Three months Ended September 30,		For the Nine months Ended September 30,	
Description	**2014**	**2013**	**2014**	**2013**
Unrealized mark-to-market gain (loss) in other comprehensive income	$ 12,451	$ (666,614)	$ -	$ 192,115
Total other comprehensive income (loss)	$ 12,451	$ (666,614)	$ -	$ 192,115

NOTE 4 FAIR VALUE MEASUREMENTS

The Company has various financial instruments that are measured at fair value in the financial statements, including commodity derivatives. The Company s financial assets and liabilities are measured using input from three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

Level 1 Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

Level 2 Inputs include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the assets or liability and inputs that are derived principally from, or corroborated by, observable market data by correlation or other means (market corroborated inputs).

Level 3 Unobservable inputs that reflect the Company s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, using internal and external data.

The following table presents the Company s assets and liabilities recognized in the balance sheet and measured at fair value on a recurring basis as of September 30, 2014 and December 31, 2013:

	Level 1	Level 2	Level 3	Total
September 30, 2014				
Liabilities:				
Commodity derivatives	$ -	$ 47,131	$ -	$ 47,131
	$ -	$ 47,131	$ -	$ 47,131
December 31, 2013				
Liabilities:				
Commodity derivatives	$ -	$ 1,019,932	$ -	$ 1,019,932
	$ -	$ 1,019,932	$ -	$ 1,019,932

The Company uses various commodity derivative instruments, including fixed price swaps. We consider the fair value of our commodity derivative instruments to be level 2 on the fair value hierarchy. The fair value of commodity derivatives is determined using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data.

NOTE 5 OTHER ASSETS

Other assets consist of the following:

	September 30, 2014	December 31, 2013
Site specific trust accounts - P&A escrow	$ 5,543,368	$ 5,521,913
Debt issuance cost, net	4,772,870	6,351,806
Restricted cash P&A bond	10,628,772	9,738,353
Other	73,995	53,758
	$ 21,019,005	$ 21,665,830

Site Specific Trust Accounts P&A Escrow

The Company maintains an escrow agreement that has been established for the purpose of assuring maintenance and administration of a performance bond which secures certain plugging and abandonment obligations assumed in the acquisition of oil and gas properties in certain fields. Changes in the escrow accounts reflect additional contributions and interest earned during 2014. See Note 9 Asset Retirement Obligations .

Debt Issuance Costs, Net

The Company capitalizes certain debt issuance costs and amortizes those costs as additional interest expense over the lives of the associated debt. Net debt issuance costs at September 30, 2014 and December 31, 2013 reflect the issuance of the 12½% Second Lien Notes in December 2012 and July 2011 and the issuance of the 10% First Lien Notes in November 2013. See Note 10 Debt .

Restricted Cash P&A Bond

Restricted Cash P&A Bond consists of cash collateral held in escrow to assure maintenance and administration of performance bonds which secures certain plugging and abandonment obligations imposed by state law. The cash collateral is reflected as a long term asset to correspond with the expected timing of the related asset retirement obligation liability. See Note 9 Asset Retirement Obligations .

NOTE 6 STOCK-BASED COMPENSATION EXPENSE

The Company periodically grants restricted stock and stock options to employees, directors and consultants. The Company is required to make estimates of the fair value of the related instruments and recognize expense over the period benefited, usually the vesting period.

Compensation Plan

In September 2011, the Company s board of directors adopted, and in June 2012 the Company s stockholders approved, the Saratoga Resources, Inc. 2011 Omnibus Equity Plan (the 2011 Plan). The 2011 Plan reserves a total of 3,000,000 shares for issuance to eligible employees, officers, directors and other service providers pursuant to grants of options, restricted stock, performance stock and other equity based compensation agreements.

Stock Option Activity

In February 2014, the Company s management approved a stock option grant to purchase an aggregate of 90,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.32 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $96,300. The options were valued using the Black-Scholes model with the following assumptions: 121% volatility; 4.5 year estimated life; zero dividends; 1.36% discount rate; and, quoted stock price and exercise price of $1.32.

In April 2014, the Company s management approved a stock option grant to purchase an aggregate of 60,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.22 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $57,000. The options were valued using the Black-Scholes model with the following assumptions: 113% volatility; 4.5 year estimated life; zero dividends; 1.47% discount rate; and, quoted stock price and exercise price of $1.22.

In April 2014, the Company s management approved a stock option grant to purchase an aggregate of 90,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.18 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $70,200. The options were valued using the Black-Scholes model with the following assumptions: 92% volatility; 4.1 year estimated life; zero dividends, 1.25% discount rate; and, quoted stock price and exercise price of $1.18.

In May 2014, the Company s management approved a stock option grant to purchase an aggregate of 60,000 shares of common stock to a non-executive employee. The options are exercisable for a term of seven years at $1.30 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $47,400. The options were valued using the Black-Scholes model with the following assumptions: 83% volatility; 4.1 year estimated life; zero dividends; 1.26% discount rate; and, quoted stock price and exercise price of $1.30.

In May 2014, the Company s board of directors approved stock option grants to purchase an aggregate of 90,000 shares of common stock to two executive officers. The options are exercisable for a term of seven years at $1.30 per share and vest 1/3 after six months and 1/3 on each of the first two grant date anniversaries. The grant date value of the options was $71,100. The options were valued using the Black-Scholes model with the following assumptions: 83% volatility; 4.1 year estimated life; zero dividends; 1.26% discount rate; and, quoted stock price and exercise price of $1.30.

In June 2014, the Company s board of directors approved a stock option grant to purchase an aggregate of 105,000 shares of common stock to non-employee directors. The options are exercisable for a term of seven years at $1.89 per share and vest 1/2 on the date of grant and 1/2 on the first anniversary of the grant date. The grant date value of the options was $103,950. The options were valued using the Black-Scholes model with the following assumptions: 72% volatility; 3.75 year estimated life; zero dividends; 1.24% discount rate; and, quoted stock price and exercise price of $1.89.

In September 2014, the Company s management approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to two non-executive employees. The options are exercisable for a term of seven years at $1.47 per share and vest 1/3 on each of the first three grant date anniversaries. The grant date value of the options was $29,700. The options were valued using the Black-Scholes model with the following assumptions: 90% volatility; 4.5 year estimated life; zero dividends; 1.62% discount rate; and, quoted stock price and exercise price of $1.47.

The following table summarizes information about stock option activity and related information for the nine months ended September 30, 2014:

	Number of Shares Underlying Options		**Weighted Average Exercise Price per Share**		**Weighted Average Grant Date Fair Value per Share**	**Weighted Average Remaining Contractual Life (in Years)**		**Aggregate Intrinsic Value [(1)]**
Outstanding at December 31, 2013	1,607,500	$	3.13	$	2.46	5.4	$	39,000
Granted	525,000		1.40		0.91	6.6		-
Exercised	(40,000)		1.53		1.53	-		-
Forfeited	(345,000)		3.69		3.69	-		-
Outstanding at September 30, 2014	1,747,500	$	2.53	$	1.77	5.3	$	41,000
Exercisable at September 30, 2014	917,500	$	3.10	$	2.30	4.6	$	41,000

(1)

The intrinsic value of an option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the option. On September 30, 2014, the last reported sales price of our common stock on the NYSE MKT was $1.18 per share.

Share-Based Compensation Expense

The following table reflects share-based compensation recorded by the Company for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Share-based compensation expense included in reported net income	$ 173,871	$ 233,132	$ 420,154	$ 769,427
Basic earnings per share effect of share-based compensation expense	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.02)

As of September 30, 2014, total unrecognized stock-based compensation expense related to non-vested stock options was $0.4 million. The unrecognized expense is expected to be recognized over a weighted average period of 0.5 years.

NOTE 7 EQUITY

Common Stock Activity

In June 2014, the Company received gross proceeds of $61,200 for 40,000 stock options exercised at $1.53 a share.

Warrant Activity

The following table summarizes information about stock warrant activity and related information for the nine months ended September 30, 2014:

	Number of Shares Underlying	Weighted Average Exercise	Weighted Average Grant	Weighted Average Remaining	Aggregate Intrinsic Value [(1)]

	Warrants	**Price per Share**	**Date Fair Value per Share**	**Contractual Life (in Years)**	
Outstanding at December 31, 2013	146,998	$ 6.64	$ 5.33	1.4	$ -
Granted	-	-	-	-	-
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at September 30, 2014	146,998	$ 6.64	$ 5.33	0.6	$ -
Exercisable at September 30, 2014	146,998	$ 6.64	$ 5.33	0.6	$ -

(1)

The intrinsic value of a warrant is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the warrant. On September 30, 2014, the last reported sales price of our common stock on the NYSE MKT was $1.18 per share.

NOTE 8 EARNINGS (LOSS) PER SHARE

A reconciliation of the components of basic and diluted net loss per common share is presented in the tables below:

	For the Three Months Ended September 30,					
	2014			2013		
	Income (Loss)	Weighted Average Common Shares Outstanding	Per Share	Income (Loss)	Weighted Average Common Shares Outstanding	Per Share
Basic:						
Loss attributable to common stock	$ (10,273,485)	30,986,601	$ (0.33)	$ (5,725,360)	30,945,242	$ (0.19)
Effect of Dilutive Securities:						
Stock options and other		-			-	
Diluted:						
Loss attributable to common stock, including assumed conversions	$ (10,273,485)	30,986,601	$ (0.33)	$ (5,725,360)	30,945,242	$ (0.19)

	For the Nine Months Ended September 30,					
	2014			2013		
	Income (Loss)	Weighted Average Common	Per Share	Income (Loss)	Weighted Average Common	Per Share

			Shares Outstanding					Shares Outstanding		
Basic:										
Loss attributable to common stock	$	(25,215,108)	30,961,106	$	(0.81)	$	(9,100,772)	30,927,802	$	(0.29)
Effect of Dilutive Securities:										
Stock options and other			-					-		
Diluted:										
Loss attributable to common stock, including assumed conversions	$	(25,215,108)	30,961,106	$	(0.81)	$	(9,100,772)	30,927,802	$	(0.29)

NOTE 9 ASSET RETIREMENT OBLIGATIONS

The Company accounts for plugging and abandonment costs in accordance with FASB Accounting Standards Codification 410-20, *Accounting for Asset Retirement Obligations.*

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations are as follows:

Balance at December 31, 2013	$ 12,649,458
Accretion expense	1,345,399
Additions	-
Revisions	-
Settlements	-
Balance at September 30, 2014	$ 13,994,857

NOTE 10 DEBT

Long-term debt consists of the following:

		September 30, 2014		December 31, 2013
10% First Lien Notes due 2015	$	54,600,000	$	54,600,000
12 ½% Second Lien Notes due 2016		125,200,000		125,200,000
Less unamortized discount		(1,158,092)		(1,603,016)
	$	178,641,908	$	178,196,984

10.0% First Lien Notes

In November 2013, the Company, and its wholly-owned subsidiaries (the Guarantors), issued $54.6 million in aggregate principal amount of 10.0% Senior Secured Notes due 2015 (the First Lien Notes) to two institutional accredited investors (the Purchasers).

The First Lien Notes were issued pursuant to Purchase Agreements (the Purchase Agreement), and under an Indenture (the First Lien Indenture), by and among the Company, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (the First Lien Trustee). The First Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed (the Guarantees) on a senior secured basis by the Guarantors and will rank equally in right of payment with our, and the Guarantors , existing and future senior indebtedness and senior in right of payment to Second Lien Notes (as defined below).

The purchase price for the First Lien Notes and Guarantees was 100% of their principal amount. We received net proceeds from the issuance and sale of the First Lien Notes of approximately $25.4 million, after commissions and estimated offering expenses, and the surrender for retirement by the Purchasers of $27.3 million in face amount of 12½% Senior Secured Notes (the Second Lien Notes).

The First Lien Notes mature on December 31, 2015, and interest, accruing at 10% per annum, is payable on the First Lien Notes on March 31, June 30, September 30 and December 31 of each year, commencing December 31, 2013.

The First Lien Indenture includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Company has the option to redeem all or a portion of the First Lien Notes at any time at 100% of the principal amount to be redeemed plus accrued and unpaid interest. Upon the occurrence of a change of control, we are required to offer to purchase the First Lien Notes at a price equal to 101% of the aggregate principal amount of First Lien Notes repurchased plus accrued and unpaid interest. Further, upon the occurrence of certain asset sales, we are required to provide notice of the same and are required to offer to purchase a defined portion of the First Lien Notes at a price equal to 100% of the principal amount of First Lien Notes repurchased plus accrued and unpaid interest.

In connection with the issuance and sale of the First Lien Notes, the Company, the First Lien Trustee and The Bank of New York Mellon Trust Company, N.A., in its capacity as trustee and collateral under the Second Lien Documents (as defined below)(the Second Lien Trustee) entered into an Intercreditor Agreement (the Intercreditor Agreement). Pursuant to the Intercreditor Agreement, the parties thereto agreed that the lien with respect to collateral securing the First Lien Indenture and related First Lien Notes and Guarantees (the First Lien Obligations) shall be senior in right, priority, operation, effect and all other respects to any lien with respect to collateral securing the obligations under that certain Indenture dated as of June 12, 2011, as supplemented or amended from time to time thereafter (the Second Lien Indenture), by and among our company, the Guarantors named therein and the Second Lien Trustee, and the related Second Lien Notes in the aggregate amount of $125.2 million (the Second Lien Obligations).

12½% Second Lien Notes

In July 2011, the Company and the Guarantors entered into a Purchase Agreement with Imperial Capital, LLC (the Initial Purchaser), relating to the issuance and sale of $127.5 million in aggregate principal amount of 12½% Senior Secured Notes due 2016. The Second Lien Notes were sold at 98.221% of par in a transaction exempt from the registration requirements of the Securities Act and were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

In December 2012, the Company and the Guarantors entered into another Purchase Agreement with the Initial Purchaser, relating to the issuance and sale of an additional $25 million in aggregate principal amount of the Second Lien Notes. The Second Lien Notes were sold at 98.58% of par in a transaction exempt from the registration requirements of the Securities Act and were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

The Second Lien Notes were issued pursuant to the Second Lien Indenture among the Company, the Guarantors named therein and Second Lien Trustee, as trustee and collateral agent and, with respect to the Second Lien Notes issued in 2012, a First Supplemental Indenture, dated December 4, 2012. The Second Lien Notes are the senior secured obligations of the Company and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with the Company s and the Guarantors existing and future senior indebtedness, subject, however, to the Intercreditor Agreement pursuant to which the First Lien Notes are senior in right, priority, operation and effect to the lien securing the Second Lien Notes.

The Second Lien Notes mature on July 1, 2016, and interest is payable on January 1 and July 1 of each year.

The Second Lien Indenture includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Company has the option to redeem all or a portion of the Second Lien Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest.

NOTE 11 COMMITMENTS AND CONTINGENCIES

Contingencies

From time to time the Company may become involved in litigation in the ordinary course of business. At September 30, 2014, the Company s management was not aware, and as of the date of this report is not aware, of any such litigation that could have a material adverse effect on its results of operations, cash flows or financial condition.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks. The Company is not aware of any environmental claims existing as of September 30, 2014, which have not been provided for, covered by insurance or otherwise have a material impact on its financial position or results of operations. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental laws will not be discovered on the Company s properties.

The Harvest Group, LLC, et al. v. Brian Carl Albrecht; Harvest Operating LLC v. The Harvest Group, LLC, et al.

In February 2010, Saratoga filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group LLC and/or Harvest Oil & Gas, LLC. The complaint alleged breach of the Purchase and Sale Agreements with the former owners arising from the underpayment or nonpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest Companies and related claims for damages. The claims against all parties other than Brian Carl Albrecht were subsequently settled and the claim against Mr. Albrecht was converted to an arbitration proceeding.

Harvest Operating, LLC, a company controlled by Mr. Albrecht, brought a separate cause of action against The Harvest Group, LLC, Harvest Oil & Gas, LLC and Saratoga Resources, Inc. (the Saratoga Parties), which cause of action was consolidated with the arbitration proceedings noted above. Harvest Operating s cause of action asserted a claim for damages based on the alleged wrongful termination of rights to use a pipeline owned and operated by the Saratoga Parties and the loss in value of a property operated by Harvest Operating based on its inability to transport production from that property via the pipeline in question.

The consolidated arbitration proceeding was conducted before a single arbitrator and, in August 2014, the arbitrator issued an Award and Reasons ruling (1) in favor of Saratoga, as relates to the royalty claim, and awarding to Saratoga $355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim, and awarding to Harvest Operating $3,757,050. As a result of such award, the Company recorded an arbitration award expense and an accrued liability of $3.4 million.

Saratoga believes that the award based on the pipeline use claim is wholly unsupported by the facts or the law and intends to file a Motion for Clarification and Remittitur to vacate the arbitrator s award relating to the pipeline claim on multiple grounds and may pursue other legal actions arising from the award.

ITEM 2

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Information

This Form 10-Q quarterly report of Saratoga Resources, Inc. (the Company) for the nine months ended September 30, 2014, contains certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created thereby. To the extent that there are statements that are not recitations of historical fact, such statements constitute forward-looking statements that, by definition, involve risks and uncertainties. In any forward-looking statement, where we express an expectation or belief as to future results or events, such expectation or belief is expressed in good faith and believed to have a reasonable basis, but there can be no assurance that the statement of expectation or belief will be achieved or accomplished.

The actual results or events may differ materially from those anticipated and as reflected in forward-looking statements included herein. Factors that may cause actual results or events to differ from those anticipated in the forward-looking statements included herein include the Risk Factors described in Item 1A of our Form 10-K for the year ended December 31, 2013.

Readers are cautioned not to place undue reliance on the forward-looking statements contained herein, which speak only as of the date hereof. We believe the information contained in this Form 10-Q to be accurate as of the date hereof. Changes may occur after that date, and we will not update that information except as required by law in the normal course of our public disclosure practices.

Additionally, the following discussion regarding our financial condition and results of operations should be read in conjunction with the financial statements and related notes contained in Item 1 of Part 1 of this Form 10-Q, as well as the Risk Factors in Item 1A and the financial statements in Item 8 of Part II of our Form 10-K for the fiscal year ended December 31, 2013.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation, exploration and production of crude oil and natural gas properties. Our lease holdings totaled approximately 52,000 acres at September 30, 2014, comprised of our principal producing properties covering approximately 32,000 acres in the transitional coastline and protected in-bay environment on parish and state leases of south Louisiana and approximately 20,000 acres of leases in the shallow Gulf of Mexico shelf.

At September 30, 2014, we operated or had interests in 104 producing wells and our principal properties covered approximately 52,000 gross/net acres, more than half of which were held by production without near-term lease expirations, across 13 fields in the transitional coastline and protected in-bay environment on parish and state leases in south Louisiana as well as in the shallow Gulf of Mexico. We own approximately 100% working interest in all our properties, with the only exception being a single well where we have an overriding royalty interest. Our net revenue interests in our properties range from 70% to 82%, with our average net revenue interest on a net acreage leasehold basis being approximately 75%. We operate over 95% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties.

2014 Developments

Drilling and Development Activities

Drilling and development and infrastructure project operations to date in 2014 are summarized as follows:

Development Drilling. During the nine months ended September 30, 2014, we completed the Rocky 3 horizontal development well in Breton Sound Block 32. The SL 1227-29 Rocky 3 well, in 14 feet of water depth, was spud on May 3rd and reached a TD of 7,178 MD/5,818 TVD on May 15th. The well was completed in the 5,800 sand with a lateral displacement of 750 feet. First production from the Rocky 3 well occurred on May 28, 2014 and the well was produced, along with other wells that produce back to Breton Sound Block 32 facilities, at a curtailed rate or shut-in due to flow line capacity restrictions. Capacity restrictions were resolved in July by the installation of an additional export flow line.

Exploratory Drilling. We did not drill any exploratory wells during the nine months ended September 30, 2014.

Recompletion and Workover Program. During the nine months ended September 30, 2014, we invested $3.7 million in 4 recompletions, all of which were successfully completed during the period, and an additional $4.1 million on 12 workovers, 8 of which were successful, 1 of which was unsuccessful, and 3 of which were still in progress at quarter end.

Infrastructure Program. During the nine months ended September 30, 2014, we invested $2.5 million in infrastructure improvements and additions to support existing production and anticipated increases in production, including facility modifications at Breton Sound Block 51 to support our gas buy-back agreement at Breton Sound Block 32, facilities upgrades in Grand Bay and Breton Sound 32, construction of a new flow line to serve Breton Sound 32, and modifications to Main Pass 46 and Main Pass 52 facilities to bulk production to Grand Bay. The facilities modifications and upgrade projects at Breton Sound Block 51 and Grand Bay were completed during the quarter ended June 30, 2014, the flow line construction project in Breton Sound 32 was completed in July 2014, and the Main Pass Blocks 46 and 52 projects were substantially complete by September 30, 2014.

Drilling and Development Plans. We have an extensive inventory of drilling opportunities, including numerous proved behind pipe and proved undeveloped opportunities as well as a number of exploratory opportunities. Our near term development plans are focused on recompletions, workovers and conversion of PDNP opportunities supported by cash on hand and cash flow.

Subsequent to quarter end we initiated a through tubing development plan consisting of 6 to 9 wells. The opportunities are focused on projects with capital exposure between $70,000 and $115,000 per well, with lower risk profiles, that are expected to provide near-term cashflow and return of capital. The first three wells were successfully completed by mid-November with the remaining projects to successively follow this work and should be complete by the end of November 2014. The first three jobs were all completed below internal cost estimates.

During the quarter ended September 30, 2014, we commenced marketing efforts to attract joint venture partners for our Grand Bay deep prospects and continued our pre-marketing efforts for our Gulf of Mexico prospects. We have devoted resources within and outside the company to preparation of comprehensive geological, engineering, marketing and related materials for a professional marketing program for presentation to prospective joint venture partners on both our Gulf of Mexico and Grand Bay deep prospects

In addition to our efforts to secure partners for our Gulf of Mexico and Grand Bay deep prospects, we are conducting reservoir simulations in Breton Sound 32 to identify additional horizontal well prospects as well as evaluating additional prospects for drilling.

Production Optimization Initiatives

During the nine months ended September 30, 2014, we undertook an exhaustive review of field operations in order to address ongoing run time issues that have adversely impacted production rates across our fields and resulted in a marked decline in production during the first two months of 2014. Substantial time was spent in the field evaluating personnel, facilities, gas lift availability and other potential causes of unexpected down time in numerous fields. As a result of such evaluation, we made extensive changes in our field operating personnel and in our Covington office personnel. We also undertook extensive repairs and maintenance projects to improve certain facilities in the field and invested in gas lift projects and salt water disposal wells. The majority of the personnel changes, facilities upgrades and other projects were completed in early March 2014 with additional personnel changes, facilities upgrades and projects continuing through September 30, 2014. We continue to monitor the results of such changes and upgrades and potential future changes and upgrades to optimize production.

Prior to implementing the changes and upgrades in early March, run times had fallen to an estimated 54% on average during January and February 2014 from 75% during fiscal 2013. Following the changes and upgrades, run times for the quarters ended June 30, 2014 and September 30, 2014 have generally exceeded 75% and average daily production for the quarters ended June 30, 2014 and September 30, 2014 rose to 1,944 barrels of oil equivalent per day (BOEPD) and 2,155 BOEPD from 1,330 BOEPD in the quarter ended March 31, 2014 which was down from 1,800 BOEPD during the fourth quarter of 2013.

While the production initiatives undertaken during the first half of 2014 have resulted in marked growth in production during the second and third quarters of 2014, our lease operating expenses for the quarter and nine month periods rose on a year-over-year basis due, largely, to increased contract labor costs and facilities maintenance and repair costs incurred as part of the production optimization initiative. Decreasing lease operating expenses is currently a focus and steps are being taken to lower costs including bringing contract employees in-house, eliminating redundant positions, managing marine transportation, optimizing our chemical program, lowering communications costs, and replacing/modifying our compressors.

Severance Tax

During the nine months ended September 30, 2014, we experienced a sharp drop in severance taxes. While the drop in severance taxes reflected lower production levels, the bulk of the decrease related to severance tax refunds attributable to exemptions for our Rocky, Zeke, and Mesa Verde wells drilled in prior years. We have also received an exemption for our Rocky 3 well drilled this year.

Compensation and Contract Labor

During the nine months ended September 30, 2014, we granted 525,000 stock options to employees and non-employee directors at weighted average exercise prices of $1.40 per share.

We recorded $420,154 of compensation charges that are reflected in general and administrative expense for the nine months ended September 30, 2014 and is attributable to equity grants during 2014 and prior years.

As of September 30, 2014, total compensation cost related to unvested stock option awards not yet recognized in earnings was approximately $0.4 million, which is expected to be recognized over a weighted average period of approximately 0.5 years.

During the nine months ended September 30, 2014, as part of our production optimization initiatives undertaken during the first half of 2014, we experienced a rise in lease operating and general and administrative expense. Operating expense was impacted by an increase in contract construction labor related to facilities work in various fields and living quarters improvements in Grand Bay. We also experienced an increased reliance on contract labor to fill certain positions in the field on a temporary basis. During the quarter ended September 30, 2014, we converted several of the contract laborers to full time employees which is expected to bring down our associated lease operating expenses in future periods. Much of the expense related to facilities improvements was completed by period end and we do not expect these costs to be recurring. The increase in general and administrative expense reflected the hiring of four additional members to our professional staff, utilization of consultants on a temporary basis to fill certain positions and assist with our Grand Bay deep and Gulf of Mexico marketing efforts and certain severance payments. Steps were taken during the quarter ended September 30, 2014 to reduce general and administrative expense, including the elimination or deferral of replacing certain positions in both our Houston and Covington offices, hiring of full-time accounting personnel to reduce the cost and reliance on third-party personnel for these services, and revising certain consulting agreements to reduce professional consultant fees. We expect these cost saving initiatives to continue in the fourth quarter of 2014.

Share Issuances for Cash

During the nine months ended September 30, 2014, we sold 40,000 shares of common stock for $61,200 pursuant to the exercise outstanding stock options.

Hedging Activities

As of September 30, 2014, we had no fixed price swaps in place.

In October 2013, we received $620,500 in proceeds for the sale of crude oil call options. The options provided for a premium of $6.80 per barrel (Bbl) for a total of 91,250 Bbls. The call options cover 250 Bbls per day beginning on April 1, 2014 and ending on March 31, 2015 at an option strike price of $103.30. The short crude oil call option, when combined with the Company s long production position, represents a covered call , and creates a $103.30 per Bbl ceiling on the price to be received during the covered period for the related production.

Legal Proceedings

During the nine months ended September 30, 2014, we participated in an arbitration proceeding relating to our long-standing claim against Brian Albrecht for underpayment of royalties relating to our original acquisition of The Harvest Group, LLC and Harvest Oil & Gas, LLC. That arbitration proceeding was consolidated with a claim asserted by Harvest Operating, LLC, a company owned by Mr. Albrecht, against Saratoga, The Harvest Group, LLC and Harvest Oil & Gas, LLC (the Saratoga Group) relating to alleged damage to the value of a property operated by Harvest Oil arising from the alleged wrongful termination of rights to use a pipeline owned by the Saratoga Group. In August, 2014, the arbitrator in the consolidated proceeding issued an Award and Reasons ruling (1) in favor of the Saratoga Group, as relates to the royalty claim, and awarding to Saratoga $355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim, and awarding to Harvest Operating $3,757,050. As a result of such award, we recorded an arbitration award expense and an accrued liability of $3.4 million.

We believe that the award based on the pipeline use claim is wholly unsupported by the facts or the law and intend to file a Motion for Clarification and Remittitur to vacate the arbitrator s award relating to the pipeline claim on multiple grounds and may pursue other legal actions arising from the award.

Results of Operations

Oil and Gas Revenue

Oil and gas revenue for the quarter ended September 30, 2014 decreased by 7.3% to $15.9 million from $17.2 million in the 2013 quarter. For the nine month period ended September 30, 2014, oil and gas revenue decreased by 23.1% to $41.7 million from $54.2 million in the 2013 period.

For the quarter ended September 30, 2014, the decrease in revenue was attributable to a 10.5% decline in oil revenues with oil production volumes essentially remaining flat and average oil prices realized declining 10.0% partially offset by a 54.6% increase in gas revenues on a 56.0% increase in gas production volumes partially offset by a 1.1% decrease in average prices realized, each as compared to the 2013 quarter. For the nine months ended September 30, 2014, the decrease in revenue was attributable to a 22.9% decline in oil revenues on a 17.9% decrease in oil production volumes and a 6.2% decrease in average oil prices realized and a 24.7% decline in gas revenues on a 34.2% decrease in gas production volumes partially offset by a 14.4% increase in average gas prices realized, each as compared to the 2013 period.

The following table discloses the oil and gas sales revenues, net oil and natural gas production volumes and average sales prices for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
Revenues				
Oil	$ 14,633,397	$ 16,345,209	$ 38,194,493	$ 49,566,017
Gas	1,315,400	850,567	3,478,012	4,619,417
Total oil and gas revenues	$ 15,948,797	$ 17,195,776	$ 41,672,505	$ 54,185,434
Production				
Oil (Bbls)	149,695	150,543	378,711	461,066
Gas (Mcf)	291,441	186,798	697,327	1,060,525
Total production (Boe)	198,268	181,676	494,932	637,820
Average sales price				

Oil (per Bbl)	$ 97.75	$ 108.58	$ 100.85	$ 107.50
Gas (per Mcf)	4.51	4.56	4.99	4.36
Total average sales price (per Boe)	$ 80.44	$ 94.65	$ 84.20	$ 84.95

Oil production was down 1 thousand barrels (MBbl), or 0.1%, and 82.4 MBbl, or 17.9%, for the quarter and nine months ended September 30, 2014, respectively, as compared to the same period in 2013.

The decrease in oil production during the 2014 nine month period reflected a combination of reduced run times particularly in the first six months of 2014, elevated decline rates in certain high production wells, increased water-cut in selected wells, gas lift gas shortages, mechanical issues and flow line capacity constraints, all of which were partially offset by the addition of production from recompletions, workovers and new drills during the second half of 2013 and the first half of 2014. The declines in oil production for the nine months were principally in Breton Sound 18 (down 59.6 MBbl), Main Pass 46 (down 17.5 MBbl) and Grand Bay (down 29.1 MBbl), all partially offset by an increase in Breton Sound 32 (up 21.9 MBbl). The declines for the nine month period in oil production in Breton Sound 18, Main Pass 46 and Grand Bay were partially offset by increased production in Breton Sound 32 attributable to the drilling of Zeke (11.6 MBbl increase), Rocky (14.4 MBbl increase) during 2013, and Rocky 3 (34.2 MBbl increase) during 2014.

Production optimization initiatives undertaken throughout 2014 resulted in increased run-time and this, along with, drilling and development activity during the second quarter of 2014 helped to increase production levels during the quarter from production volumes in the first and second quarters of 2014. For the quarter ended September 30, 2014, oil production was essentially flat to the same period in 2013 and up substantially from production levels early in 2014. The increase in production levels during 2014, on a quarter over quarter basis, was attributable to projects undertaken during the year including, facilities upgrades in Grand Bay (compressors and bulking), flow-line installation at Breton Sound 32, workover and recompletion activity focused on assuring gas lift gas supply, and a full quarter of production from Rocky 3.

Natural gas production was up 104.6 million cubic feet (MMcf), or 56.0%, and down 363.2 MMcf, or 34.2%, for the quarter and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013.

The increase in gas production during the 2014 quarter was a result of recompletions and workovers on wells in the Grand Bay / Main Pass 46 and Breton Sound 18, respectively, partially offset by depletion and natural decline in several wells and down-hole conditions that resulted in a production decline from a gas well. The increase in gas production for the quarter was principally in Grand Bay (up 87.6 MMcf) and Main Pass 46 (up 75.7 MMcf) partially offset by declines in Breton Sound 32 (down 37.2 MMcf) and Main Pass 25 (down 16.3 MMcf). The decrease in gas production during the 2014 nine month period reflected a combination of recompletion of a prior gas producer as an oil well, depletion and natural decline in several wells, and down-hole conditions that resulted in a production decline from a gas well. The declines in gas production for the nine months were principally in Grand Bay (down 319.0 MMcf), Main Pass 52 (down 90.9 MMcf), Main Pass 25 (down 36.7 MMcf) and Breton Sound 32 (down 43.3 MMcf). At Grand Bay, the decline in gas production reflected natural decline and depletion of two separate dually completed wells and the recompletion of a previous gas producer uphole to an oil zone. At Main Pass 25/52 Fields, the decline in gas production reflected the depletion of long-time gas producers and downhole conditions in a well. Partially offsetting the decreases were gas-targeted recompletions at Grand Bay, Breton Sound 18/32, and Main Pass 46, which collectively added 81.2 MMcf and 178.0 MMcf of gas production for the quarter and nine-month periods ended September 30, 2014 compared to the same periods in 2013.

As noted above, as of the third quarter of 2014 run-time issues, flow line capacity restrictions and certain mechanical and facilities issues that contributed to declines in oil and gas production have been addressed in part or in whole and production rates have risen over the course of 2014.

The decrease in realized hydrocarbon prices reflects a weakness in global oil prices during the latter half of the quarter, which trend continued following quarter end.

Other Revenues

Other revenue consists principally of production handling fees and contract operator fees received.

Operating Expenses

Operating expenses increased by 6.3% to $20.8 million for the quarter ended September 30, 2014 from $19.5 million in the 2013 quarter. The following table sets forth the components of operating expenses for the 2014 and 2013 quarters:

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 6,642,635	$ 33.51	$ 5,490,268	$ 30.22
Workover expense	1,750,760	8.83	848,094	4.67
Exploration expense	225,949	1.14	462,994	2.55
Loss on plugging and abandonment	-	-	727,039	4.00
Depreciation, depletion and amortization	4,839,858	24.41	4,919,418	27.08
Impairment expense	-	-	2,179,075	11.99
Accretion expense	448,466	2.26	638,097	3.51
General and administrative	2,401,158	12.11	2,365,501	13.02
Severance taxes	1,058,787	5.34	1,900,292	10.46
Arbitration loss	3,400,000	17.15	-	-
	$ 20,767,613	$ 104.75	$ 19,530,778	$ 107.50

Operating expenses decreased by 2.6% to $50.3 million for the nine months ended September 30, 2014 from $51.6 million in the 2013 period. The following table sets forth the components of operating expenses for the 2014 and 2013 periods:

	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 18,439,907	$ 37.26	$ 15,293,422	$ 23.97
Workover expense	4,050,528	8.18	2,277,226	3.57
Exploration expense	647,599	1.31	746,965	1.17
Loss on plugging and abandonment	-	-	727,039	1.14
Depreciation, depletion and amortization	12,089,913	24.43	15,790,454	24.76
Impairment expense	-	-	2,179,075	3.42
Accretion expense	1,345,399	2.72	1,914,291	3.00
General and administrative	7,456,116	15.06	6,804,243	10.67
Severance taxes	2,869,129	5.80	5,892,904	9.24
	3,400,000	6.87	-	-
	$ 50,298,591	$ 101.63	$ 51,625,619	$ 80.94

The changes in operating expenses were primarily attributable to the factors discussed below.

Lease Operating Expense

Lease operating expenses for the quarter ended September 30, 2014 increased 21.0%, to $6.6 million, from $5.5 million in the 2013 quarter and 20.6% for the nine months ended September 30, 2014, to $18.4 million, from $15.3 million in the 2013 period. The increase in lease operating expense for the nine months ended September 30, 2014 was primarily due to (i) increased contract construction labor costs incurred in Grand Bay, Breton Sound, and Main Pass 25 Fields; (ii) one-time contract construction labor and building repair and maintenance expenses for living quarters in Grand Bay Field; (iii) increased contract pumping costs in Breton Sound and Main Pass 25/46 Fields for services provided to replace reduced field personnel as part of first quarter 2014 initiative to increase operational efficiencies; (iv) increased surface equipment repair and maintenance expense in Breton Sound 32 and Grand Bay Fields; (v) increased equipment rental expense for Breton Sound 32 and Grand Bay Fields; (vi) increased platform/flow lines repair and maintenance expenses in Main Pass 25/46 and Breton Sound 51 Fields; and (vii) increased well maintenance expense in Breton Sound 32 Field, largely due to a one time flow line well maintenance charge in March of 2014, in addition to some increases in Grand Bay and Main Pass 25/46 Fields. An estimated $1.2 million of the increase in lease operating expense related to contract construction labor, equipment repairs and maintenance, and well maintenance charges that were associated with our production optimization initiatives. We will seek to reduce our reliance on, and cost of, contract operating personnel as we seek to internally hire high-quality personnel for our field operations. We expect those expenses will decrease and result in future lease operating expenses leveling off. The increases in contract construction labor, contract pumping gaugers, repair and maintenance expenses were partially offset by decreases in slickline operations, payroll/payroll burden, and regulatory compliance expenses.

Operating costs in our fields have historically been relatively high due to water handling, the need for gas lift to maintain oil production and the need for marine transportation in the shallow water, bay environment. For the quarter ended September 30, 2014, the increase in lease operating expense on a per barrel of oil equivalent (BOE) basis was attributable to the increase in, and the fixed nature of, certain lease operating expenses partially offset by increases in production volumes. For the nine months ended September 30, 2014, the increase in lease operating expense on a per BOE basis was attributable to both the increase in, and fixed nature of, certain lease operating expenses and decreases in production volumes.

Workover Expense

Workover expense for the quarter ended September 30, 2014 increased to $1,750,760 from $848,094 in the 2013 quarter and increased to $4,050,528 from $2,277,226 for the nine months ended September 30, 2014 from the 2013 period. The change in workover expense was attributable to variances in the number of workovers undertaken during the respective periods.

Exploration Expense

Exploration expense for the quarter ended September 30, 2014 decreased to $225,949 from $462,994 in the 2013 quarter and decreased to $647,599 from $746,965 for the nine months ended September 30, 2014. Exploration expense consists primarily of investments in field studies relating to our Gulf of Mexico shelf acreage.

Depreciation, Depletion and Amortization (DD&A)

Depreciation, depletion and amortization for the quarter ended September 30, 2014 decreased 1.6% to $4,839,858 from $4,919,418 in the 2013 quarter and decreased to $24.41 per BOE from $27.08 per BOE in the 2013 quarter. Depreciation, depletion and amortization for the nine months ended September 30, 2014 decreased 23.4% to $12,089,913 from $15,790,454 in the 2013 period and decreased to $24.43 per BOE from $24.76 per BOE in the 2013 period.

We utilize the successful efforts method of accounting for oil and gas producing activities. Under this method, DD&A is computed on the units-of-production method separately on each individual property and includes the accrual of future plugging and abandonment costs.

The decrease in DD&A expense during the nine months ended September 30, 2014 was primarily attributable to production declines as compared to the 2013 period.

Accretion expense

Accretion expense relating to our asset retirement obligations decreased to $448,466 from $638,097 for the quarter ended September 30, 2014 as compared to the 2013 quarter and decreased to $1,345,399 from $1,914,291 for the nine months ended September 30, 2014 as compared to the 2013 period.

The decrease in accretion expense was attributable to changes in the anticipated plugging dates and discount rates used in calculating the asset retirement obligation for certain fields.

General and Administrative

General and administrative (G&A) expense for the quarter ended September 30, 2014 increased 1.5% to $2,401,158 as compared to $2,365,501 in the 2013 quarter, and increased 9.6% for the nine months ended September 30, 2014 to $7,456,116 as compared to $6,804,243 in the 2013 period. The increase in G&A expense was primarily due to increased consulting fees and legal and professional fees, partially offset by a decrease in non-cash stock compensation expense.

Severance Taxes

Severance taxes for the quarter ended September 30, 2014 decreased to $1,058,787 from $1,900,292 in the 2013 quarter and decreased to $2,869,129 for the nine months ended September 30, 2014 from $5,892,904 for the 2013 period. The decrease was primarily attributable to production declines and the horizontal well severance tax exemptions obtained for our Rocky, Zeke, and Rocky 3 wells and the deep well severance tax exemption obtained for our Mesa Verde well. Some of these exemptions resulted in refunds of severance taxes paid in prior periods which totaled $0.5 million.

Arbitration Loss

As a result of the arbitration loss rendered during the current quarter, we recorded an arbitration award expense of $3.4 million during the quarter and nine months ended September 30, 2014.

Other Income (Expense), Net

Net other expense increased to $6.1 million for the quarter ended September 30, 2014 from $5.4 million for the 2013 quarter and increased to $18.1 million for the nine months ended September 30, 2014 from $15.9 million in the 2013 period.

Interest expense reflects interest incurred on debt under our 10% First Lien Notes and 12.5% Second Lien Notes. The increase in interest expense was attributable to our placement of $54.6 million in principal of the First Lien Notes in November 2013, partially offset by a simultaneous reduction of $27.3 million in principal of the Second Lien Notes.

Income Tax Expense (Benefit)

For the quarter ended September 30, 2014 we recorded an income tax expense of $33,795 compared to a benefit of $2,683,382 during the 2013 quarter. For the nine months ended September 30, 2014 we recorded an income tax expense of $156,060 compared to a benefit of $4,196,914 during the 2013 period.

The increase in income tax expense is primarily due to the fact that we recorded a valuation allowance for the entire balance of our net deferred tax asset at December 31, 2013 and accordingly, did not recognize any deferred tax benefit as a result of the current period losses.

Our effective tax rates were different than our federal statutory tax rate due to Louisiana state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Financial Condition

Liquidity and Capital Resources

Our principal requirements for capital are to fund our day-to-day operations and exploration, development and acquisition activities and to satisfy our contractual obligations, primarily for the repayment of debt.

During 2013 and 2014 we funded operations out of operating cash flow and cash on hand, which funds have been supplemented by the issuance of $27.3 million of First Lien Notes for cash in November 2013. During 2013 and 2014, we did not have access to available capital under a revolving credit agreement and do not at this time have a revolving credit facility.

We developed, and beginning in 2011 commenced, a layered, multi-faceted development and maintenance program designed to achieve short-, mid- and long-term objectives. Short-term objectives are focused on restoration of shut-in and curtailed production through investments in infrastructure and deferred maintenance and recompletions, workovers and thru-tubing plugbacks each designed to increase or restore production volumes from wells producing below capacity and an inventory of proved developed nonproducing opportunities. Mid-term, following or in conjunction with execution of short-term opportunities, our focus is on the development of an inventory of proved undeveloped opportunities within our inventory of proved undeveloped wells targeting normally pressured oil and gas. Long-term, following or in conjunction with the execution of our short- and mid-term opportunities, our focus is on continuing development of our reserves and exploratory drilling of deep shelf opportunities. During 2013 and 2014, while continuing to advance short-term objectives associated with continual investment in recompletions, workovers and infrastructure, we focused on our mid-term objectives through drilling proved undeveloped opportunities.

As a result of reduced production volumes early in the year, and resulting operating losses and declines in cash flow, our liquidity position has worsened during 2014. We are presently curtailing development of our proved undeveloped opportunities in favor of building our cash position to, among other things, support our scheduled payments of interest on outstanding debt, which payments, totaling $9.2 million, are due on December 31, 2014 and January 1, 2015.

While we believe that our cash on hand and cash flows from operations will support operations, given the declines in crude oil and natural gas prices subsequent to September 30, 2014, there is no assurance that we will have adequate cash on hand to pay in full our upcoming interest payments. Even if we have sufficient cash to support our upcoming interest payments, absent additional financing, we do not expect to have sufficient funds on hand or available from operations to support planned development operations over the next twelve months. Further, should we be unable to have the recent arbitration award reversed and be required to pay such award, our existing cash reserves would be materially reduced. We are presently evaluating options for bringing in additional financing to support our liquidity needs and planned development program. We do not, however, presently have any commitments to provide financing and there is no assurance that any additional financing will be provided on acceptable terms or at all. Should we be unable to pay our scheduled interest payments or to reach acceptable accommodations with our lenders regarding such payments, we may be subject to legal actions instituted by our lenders which may include foreclosure of liens and possible loss of assets.

Cash, Cash Flows and Working Capital

We had a cash balance of $6.4 million and working capital deficit of $2.1 million at September 30, 2014 as compared to a cash balance of $32.5 million and working capital of $20.4 million at December 31, 2013. The decrease in cash on hand was primarily attributable to the interest payment on our 12.5% Second Lien Notes in July 2014 and on our 10% First Lien Notes in September 2014 and to reductions in operating cash flow. The decrease in our working capital was primarily attributable to the reduction in our cash balance and the arbitration award.

Operations used cash flow of $10.5 million for the nine months ended September 30, 2014 as compared to providing $3.5 million for the nine months ended September 30, 2013. The change in operating cash flows during 2014 was principally attributable to reduced profitability resulting from lower production volumes and changes in our operating assets and liabilities.

Investing activities used cash totaling $14.4 million during the nine months ended September 30, 2014 as compared to $25.2 million used during 2013. The decrease in cash used in investing activities was primarily due to a reduction in developmental wells drilled during the period.

Financing activities used cash flows of $1.3 million during the nine months ended September 30, 2014 as compared to $1.0 million used during 2013. Cash flows used by financing activities during both periods primarily related to repayments on our short-term notes payable.

Debt

At September 30, 2014, we had $178.6 million of indebtedness outstanding, consisting of $54.6 million in face amount of 10% First Lien Notes, less $0.2 million of debt discount, and $125.2 million in face amount of 12½% Senior Secured Notes due 2016 less $1.0 million of debt discount.

We had no letters of credit outstanding at September 30, 2014 that were not fully collateralized by cash.

10% First Lien Notes. In November 2013, we issued $54.6 million in aggregate principal amount of our 10.0% Senior Secured Notes due 2015 (the First Lien Notes).

The 10% First Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our, and the Guarantors , existing and future senior indebtedness and senior in right of payment to 12½% Second Lien Notes.

The 10% First Lien Notes mature on December 31, 2015, and interest, accruing at 10% per annum, is payable on the notes on March 31, June 30, September 30 and December 31 of each year, commencing December 31, 2013.

We have the option to redeem all or a portion of the 10% First Lien Notes at any time at 100% of the principal amount to be redeemed plus accrued and unpaid interest. Upon the occurrence of a change of control, we are required to offer to purchase the 10% First Lien Notes at a price equal to 101% of the aggregate principal amount of 10% First Lien Notes repurchased plus accrued and unpaid interest. Further, upon the occurrence of certain asset sales, we are required to provide notice of the same and are required to offer to purchase a defined portion of the 10% First Lien Notes at a price equal to 100% of the principal amount of 10% First Lien Notes repurchased plus accrued and unpaid interest.

In connection with the issuance and sale of the 10% First Lien Notes, we, the First Lien Trustee and Second Lien Trustee entered into an Intercreditor Agreement. Pursuant to the Intercreditor Agreement, the parties thereto agreed that the lien with respect to collateral securing the First Lien Indenture and related First Lien Obligations shall be senior in right, priority, operation, effect and all other respects to any lien with respect to collateral securing the obligations under Second Lien Indenture, by and among our company, the Guarantors named therein and the Second Lien Trustee, and the related 12½% Second Lien Notes.

12½% Second Lien Notes. In July 2011, we issued $127.5 million of our 12½% Second Lien Notes and retired all obligations owing under our prior credit facilities and all outstanding letter of credit obligations. In December 2012, we issued an additional $25.0 million of our 12½% Second Lien Notes. In November 2013, we retired $27.3 million in face amount of our 12½% Second Lien Notes pursuant to the issuance of a like amount of 10% First Lien Notes described above.

The 12½% Second Lien Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our and the Guarantors existing and future senior indebtedness, subject, however, to the Intercreditor Agreement pursuant to which the 10% First Lien Notes are senior in right, priority, operation and effect to the lien securing the 12½% Second Lien Notes. The 12½% Second Lien Notes mature on July 1, 2016, and interest is payable on the notes on January 1 and July 1 of each year. We have the option to redeem all or a portion of the 12½% Second Lien Notes at any time on or after January 1, 2014 at the redemption prices specified in the Second Lien Indenture pursuant to which the 12½% Second Lien Notes were issued plus accrued and unpaid interest.

Capital Expenditures, Commitments and Contingencies

Our capital spending for the nine months ended September 30, 2014 was $16.0 million relating primarily to development of our oil and gas properties, including the drilling of our Rocky 3 horizontal well ($5.6 million), four recompletions ($3.7 million), twelve workovers ($4.1 million), investments in multiple infrastructure projects ($2.5 million) and other leasehold costs ($0.1 million). Capital expenditures were up from $12.2 million during the 2013 period.

As noted, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations. Actual levels of capital expenditures in any year may vary significantly due to many factors, including the extent to which properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services.

With the decline in our production early in the year and the resulting operating losses and declines in cash flow we are presently curtailing development of our proved undeveloped properties while we build our cash position.

While we believe that we have meritorious arguments for the reconsideration and reversal of the $3.7 million arbitration loss to Harvest Operating, if we are unsuccessful in our efforts to reverse the award, we will be subject to payment of the arbitrator s award which would materially adversely affect our cash position and possibly result in further curtailing of various operations that would otherwise be carried out.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at September 30, 2014.

Inflation

We believe that inflation has not had a significant impact on our operations since inception.

ITEM 3

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market-risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Prices have fluctuated significantly during the last five years and such volatility is expected to continue, and the range of such price movement is not predictable with any degree of certainty. In the normal course of business we periodically enter into commodity derivative transactions, including fixed price and ratio swaps to mitigate exposure to commodity price movements, but not for trading or speculative purposes.

As of September 30, 2014, we had the following hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Strike Price	Premium	Total Bbls
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	45,500
						45,500

We are exposed to market risk on derivative instruments to the extent of changes in market prices of crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. The change in the fair value of our commodity derivative contracts that are effective are recorded to Accumulated Other Comprehensive Income (Loss) in Stockholders Equity in the Consolidated Balance Sheet. The ineffective portion of the change in fair market value of derivatives is recorded currently in earnings as a component of Oil and Gas Hedging in the Consolidated Statements of Operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities.

Koch Supply & Trading, LP is the counterparty to our present covered call option. We are exposed to credit losses in the event of nonperformance by the counterparty on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparty over the term of the commodity derivatives positions.

Interest Rate Risk

All of our debt has a fixed interest rate, and we are not presently exposed to interest rate risk. In the event that we establish a new revolving credit facility we expect that such facility will provide for interest at a floating rate and that borrowing under such facility will expose us to risk of changing interest rates.

ITEM 4

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Under the supervision and the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation as of September 30, 2014 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were not effective as of September 30, 2014.

Changes in Internal Control over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) occurred during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II

ITEM 1

LEGAL PROCEEDINGS

The Harvest Group, LLC, et al. v. Brian Carl Albrecht; Harvest Operating LLC v. The Harvest Group, LLC, et al.

In February 2010, Saratoga filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group LLC and/or Harvest Oil & Gas, LLC. The complaint alleged breach of the Purchase and Sale Agreements with the former owners arising from the underpayment or nonpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest Companies and related claims for damages. The claims against all parties other than Brian Carl Albrecht were subsequently settled and the claim against Mr. Albrecht was converted to an arbitration proceeding.

Harvest Operating, LLC, a company controlled by Mr. Albrecht, brought a separate cause of action against The Harvest Group, LLC, Harvest Oil & Gas, LLC and Saratoga Resources, Inc. (the Saratoga Parties), which cause of action was consolidated with the arbitration proceedings noted above. Harvest Operating s cause of action asserted a claim for damages based on the alleged wrongful termination of rights to use a pipeline owned and operated by the Saratoga Parties and the loss in value of a property operated by Harvest Operating based on its inability to transport production from that property via the pipeline in question.

The consolidated arbitration proceeding was conducted before a single arbitrator and, in August 2014, the arbitrator issued an Award and Reasons ruling (1) in favor of Saratoga, as relates to the royalty claim, and awarding to Saratoga \$355,879, and (2) in favor of Harvest Operating, as relates to the pipeline use claim, and awarding to Harvest Operating \$3,757,050.

Saratoga believes that the award based on the pipeline use claim is wholly unsupported by the facts or the law and intends to file a Motion for Clarification and Remittitur to vacate the arbitrator s award relating to the pipeline claim on multiple grounds and may pursue other legal actions arising from the award.

ITEM 6

EXHIBITS

Exhibit No.	**Description**
31.1	Certification of CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of CEO Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of CFO Pursuant to 18 U.S.C. Section 1350, as Adopted 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.DEF	XBRL Definition Linkbase Document
101.LAB	XBRL Labels Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

SIGNATURES

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

	SARATOGA RESOURCES, INC.	
Date: November 14, 2014		
	By:	/s/ Thomas Cooke Thomas Cooke Chief Executive Officer
	By:	/s/ John Ebert John Ebert Vice President Finance and Business Development