SARATOGA RESOURCES INC /TX
Form 10-Q
August 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 June 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 August 8, 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)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,348,287	$ 32,547,380
Accounts receivable	8,538,626	6,758,572
Prepaid expenses and other	2,292,051	1,056,350
Other current asset	150,000	150,000
Total current assets	29,328,964	40,512,302
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	296,860,181	286,441,663
Other	1,011,076	892,694
	297,871,257	287,334,357
Less: Accumulated depreciation, depletion and amortization	(108,338,751)	(101,088,696)
Total property and equipment, net	189,532,506	186,245,661
Other assets, net	20,507,462	21,665,830
Total assets	$ 239,368,932	$ 248,423,793
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 9,775,898	$ 5,391,648
Revenue and severance tax payable	4,271,363	3,754,812
Accrued liabilities	8,646,937	9,807,935
Derivative liabilities short term	593,363	837,758
Short-term notes payable	1,428,692	338,512
Total current liabilities	24,716,253	20,130,665
Long-term liabilities:		
Asset retirement obligation	13,546,391	12,649,458
Long-term debt, net of unamortized discount of $1,311,633 and $1,603,016, respectively	178,488,367	178,196,984
Derivative liabilities	-	182,174

Total long-term liabilities		192,034,758		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 June 30, 2014 and December 31, 2013, respectively		30,987		30,947
Additional paid-in capital		78,472,807		78,165,364
Accumulated other comprehensive loss		(12,451)		-
Retained deficit		(55,873,422)		(40,931,799)
Total stockholders' equity		22,617,921		37,264,512
Total liabilities and stockholders' equity	$	239,368,932	$	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 June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
Revenues:				
Oil and gas revenues	$ 15,120,717	$ 17,727,757	$ 25,723,708	$ 36,989,658
Oil and gas hedging	(201,456)	1,139,217	859,667	490,837
Other revenues	72,426	82,466	148,601	246,349
Total revenues	14,991,687	18,949,440	26,731,976	37,726,844
Operating Expense:				
Lease operating expense	6,304,457	5,200,113	11,797,272	9,803,154
Workover expense	107,582	1,167,870	2,299,768	1,429,132
Exploration expense	200,298	115,687	421,650	283,971
Depreciation, depletion and amortization	4,507,996	5,662,542	7,250,055	10,871,036
Accretion expense	448,467	638,097	896,933	1,276,194
General and administrative	2,702,388	2,335,208	5,054,958	4,438,742
Severance taxes	1,309,592	1,901,558	1,810,342	3,992,612
Total operating expenses	15,580,780	17,021,075	29,530,978	32,094,841
Operating income (loss)	(589,093)	1,928,365	(2,799,002)	5,632,003
Other income (expense):				
Interest income	17,027	10,345	33,348	18,460
Interest expense	(6,040,171)	(5,312,111)	(12,053,704)	(10,537,088)
Total other expense	(6,023,144)	(5,301,766)	(12,020,356)	(10,518,628)
Net loss before reorganization expense and income taxes	(6,612,237)	(3,373,401)	(14,819,358)	(4,886,625)
Reorganization expense	-	-	-	2,319
Net loss before income taxes	(6,612,237)	(3,373,401)	(14,819,358)	(4,888,944)
Income tax expense (benefit)	40,199	(1,059,382)	122,265	(1,513,532)
Net loss	$ (6,652,436)	$ (2,314,019)	$ (14,941,623)	$ (3,375,412)
Other comprehensive loss				

Unrealized gain (loss) on derivative instruments		(112,804)		696,969		(12,451)		858,729
Total comprehensive loss	$	(6,765,240)	$	(1,617,050)	$	(14,954,074)	$	(2,516,683)
Net loss per share:								
Basic	$	(0.21)	$	(0.07)	$	(0.48)	$	(0.11)
Diluted	$	(0.21)	$	(0.07)	$	(0.48)	$	(0.11)
Weighted average number of common shares outstanding:								
Basic		30,949,678		30,926,766		30,948,148		30,918,938
Diluted		30,949,678		30,926,766		30,948,148		30,918,938

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

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

	For the Six Months Ended June 30,	
	2014	**2013**
Cash flows from operating activities:		
Net loss	$ (14,941,623)	$ (3,375,412)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	7,250,055	10,871,036
Accretion expense	896,933	1,276,194
Amortization of debt issuance costs	1,199,287	658,970
Amortization of debt discount	291,383	240,074
Stock-based compensation	246,282	536,294
Deferred tax benefit	-	(1,579,129)
Unrealized gain on hedges	(1,059,520)	(882,731)
Changes in operating assets and liabilities:		
Accounts receivable	(1,780,054)	4,367,785
Prepaids and other	371,578	397,218
Accounts payable	176,440	(973,441)
Revenue and severance tax payable	516,551	(1,210,374)
Payments to settle asset retirement obligations	-	(309,832)
Accrued liabilities	(460,697)	667,160
Net cash (used in) provided by operating activities	(7,293,385)	10,683,812
Cash flows from investing activities:		
Additions to oil and gas property	(6,290,509)	(11,942,098)
Additions to other property and equipment	(118,382)	(73,533)
Other assets	(40,919)	(274,064)
Net cash used in investing activities	(6,449,810)	(12,289,695)
Cash flows from financing activities:		
Proceeds from issuance of common stock	61,200	15,045
Repayment of short-term notes payable	(517,098)	(542,616)
Net cash used in financing activities	(455,898)	(527,571)
Net decrease in cash and cash equivalents	(14,199,093)	(2,133,454)
Cash and cash equivalents - beginning of period	32,547,380	32,302,313
Cash and cash equivalents - end of period	$ 18,348,287	$ 30,168,859
Supplemental disclosures of cash flow information:		
Cash paid for income taxes	$ 122,265	$ 65,597
Cash paid for interest	10,557,901	9,551,144
Non-cash investing and financing activities:		
Unrealized gain (loss) on derivative instruments	$ (12,451)	$ 858,729

Accounts payable for oil and gas additions	4,207,809	164,836
Accrued liabilities for oil and gas additions	(79,800)	118,957
Prepaid insurance financed with debt	1,607,278	1,523,305

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

SARATOGA RESOURCES, INC.

Notes to Consolidated Financial Statements

June 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 $18.1 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 six months ended June 30, 2014 and 2013, we did not recognize any impairment expense.

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 June 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 June 30, 2014, the Company had the following hedge contracts outstanding:

Instrument	**Beginning Date**	**Ending Date**	**Fixed Price**	**Strike Price**	**Premium**	**Total Bbls**
Fixed Price Swap	July 1, 2014		$ 106.95	$ -	$ -	23,000

		September 30, 2014				
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	68,500
						91,500

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

Description	**June 30, 2014**	**December 31, 2013**
Current liabilities:		
Commodity derivatives	$ 593,363	$ 837,758
	$ 593,363	$ 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 six months ended June 30, 2014 and 2013:

	For the Three months Ended June 30,		For the Six months Ended June 30,	
Description	**2014**	**2013**	**2014**	**2013**
Unrealized mark-to-market gain (loss)	$ (33,440)	$ 716,223	$ 1,059,520	$ 882,731
Realized gain (loss) on settlements	(168,016)	422,994	(199,853)	(391,894)
Total gain (loss) on commodity derivative instruments	$ (201,456)	$ 1,139,217	$ 859,667	$ 490,837

	For the Three months Ended June 30,		For the Six months Ended June 30,	
Description	**2014**	**2013**	**2014**	**2013**
Unrealized mark-to-market gain (loss) in other comprehensive income	$ (112,804)	$ 696,969	$ (12,451)	$ 858,729
Total other comprehensive income (loss)	$ (112,804)	$ 696,969	$ (12,451)	$ 858,729

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 June 30, 2014 and December 31, 2013:

	Level 1	Level 2	Level 3	Total
June 30, 2014				
Liabilities:				
Commodity derivatives	$ -	$ 593,363	$ -	$ 593,363
	$ -	$ 593,363	$ -	$ 593,363
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:

		June 30, 2014		December 31, 2013
Site specific trust accounts - P&A escrow	$	5,542,595	$	5,521,913
Debt issuance cost, net		5,152,519		6,351,806
Restricted cash P&A bond		9,738,353		9,738,353
Other		73,995		53,758
	$	20,507,462	$	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 June 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.

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

	Number of Shares Underlying Options	**Weighted Average Exercise Price per Share**	**Weighted Average Grant Date Fair Value per**	**Weighted Average Remaining Contractual Life (in**	**Aggregate Intrinsic Value (1)**

			Share	**Years)**	
Outstanding at December 31, 2013	1,607,500	$ 3.13	$ 2.46	5.4	$ 39,000
Granted	495,000	1.40	0.90	6.8	193,200
Exercised	(40,000)	1.53	1.53	-	-
Forfeited	(225,000)	4.06	4.05	-	-
Outstanding at June 30, 2014	1,837,500	$ 2.58	$ 1.86	5.4	$ 284,425
Exercisable at June 30, 2014	925,000	$ 3.17	$ 2.51	5.0	$ 73,825

(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 June 30, 2014, the last reported sales price of our common stock on the NYSE MKT was $1.76 per share.

Share-Based Compensation Expense

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2014	**2013**	**2014**	**2013**
Share-based compensation expense included in reported net income	$ 240,253	$ 373,252	$ 246,282	$ 536,294
Basic earnings per share effect of share-based compensation expense	$ (0.01)	$ (0.01)	$ (0.01)	$ (0.02)

As of June 30, 2014, total unrecognized stock-based compensation expense related to non-vested stock options was $0.6 million. The unrecognized expense is expected to be recognized over a weighted average period of 0.6 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 six months ended June 30, 2014:

	Number of Shares Underlying Warrants	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	146,998	$ 6.64	$ 5.33	1.4	$ -
Granted	-	-	-	-	-
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at June 30, 2014	146,998	$ 6.64	$ 5.33	0.9	$ -
Exercisable at June 30, 2014	146,998	$ 6.64	$ 5.33	0.9	$ -

(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 June 30, 2014, the last reported sales price of our common stock on the NYSE MKT was $1.76 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 June 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	$ (6,652,436)	30,949,678	$ (0.21)	$ (2,314,019)	30,926,766	$ (0.07)
Effect of Dilutive Securities:						
Stock options and other		-			-	
Diluted:						
Loss attributable to common stock, including assumed conversions	$ (6,652,436)	30,949,678	$ (0.21)	$ (2,314,019)	30,926,766	$ (0.07)

	For the Six Months Ended June 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	$	(14,941,623)	30,948,148	$	(0.48)	$	(3,375,412)	30,918,938	$	(0.11)
Effect of Dilutive Securities:										
Stock options and other			-					-		
Diluted:										
Loss attributable to common stock, including assumed conversions	$	(14,941,623)	30,948,148	$	(0.48)	$	(3,375,412)	30,918,938	$	(0.11)

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	896,933
Additions	-
Revisions	-
Settlements	-
Balance at June 30, 2014	$ 13,546,391

NOTE 10 DEBT

Long-term debt consists of the following:

		June 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		(1,311,633)		(1,603,016)
	$	178,488,367	$	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 June 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 June 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.

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 six months ended June 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 June 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 June 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 six months ended June 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 along with other wells that produce back to Breton Sound Block 32 facilities, were produced at a curtailed rate or shut-in over the balance of the quarter 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 six months ended June 30, 2014.

Recompletion and Workover Program. During the six months ended June 30, 2014, we invested $3.7 million in 4 recompletions, all of which were successfully completed during the period, and an additional $2.3 million on 9 workovers, 7 of which were successfully completed during the period and 2 of which were still in progress at quarter end.

Two of the principal wells included in the recompletion and workover program during the quarter ended June 30, 2014 were wells targeting additional gas supply to support field wide gas lift needs.

Infrastructure Program. During the six months ended June 30, 2014, we invested $1.0 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 and construction of a new flow line to serve Breton Sound 32. The facilities modifications and upgrade projects were completed during the quarter ended June 30, 2014 and the flow line construction project in Breton Sound 32 was completed following quarter end in July 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 proved undeveloped opportunities and conversion of PDNP opportunities.

During the quarter and six months ended June 30, 2014 we continued pre-marketing efforts to attract joint venture partners for our Gulf of Mexico prospects, as well as some of the Grand Bay deep prospects. We have devoted resources within and outside the company to preparation of comprehensive geological, engineering, marketing and related materials to commence a professional marketing program for presentation to prospective joint venture partners on both our Gulf of Mexico and Grand Bay deep prospects. Following quarter end, we completed pre-marketing efforts and commenced our formal marketing program to prospective participants in the first of our Grand Bay deep prospects. We anticipate commencement of a similar formal marketing program to prospective participants in our Gulf of Mexico prospects during the second half of 2014.

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. Consistent with our historical practice, we do not plan to conduct additional drilling operations through the peak of the Gulf hurricane season but will look to resume drilling operations in either the fourth quarter of 2014 or the first quarter of 2015.

Production Optimization Initiatives

During the six months ended June 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. Senior management, together with consultants retained by Saratoga, spent substantial time 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 June 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 quarter ended June 30, 2014 averaged an estimated 77% (80% during June) and average daily production for the quarter ended June 30, 2014 rose to 1,944 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 quarter of 2014, our lease operating expenses for the quarter and six 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.

Severance Tax

During the six months ended June 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.

Compensation and contract labor

During the six months ended June 30, 2014, we granted 495,000 stock options to employees and non-employee directors at weighted average exercise prices of $1.40 per share.

We recorded $246,282 of compensation charges that are reflected in general and administrative expense for the six months ended June 30, 2014 and is attributable to equity grants during 2014 and prior years.

As of June 30, 2014, total compensation cost related to unvested stock option awards not yet recognized in earnings was approximately $0.6 million, which is expected to be recognized over a weighted average period of approximately 0.6 years.

During the six months ended June 30, 2014, as part of our production optimization program, certain field and technical personnel left the company and we hired four additional members of our professional staff and utilized contract labor on a temporary basis to fill certain positions in the field. As a result of the use of contract labor, we experienced a rise in lease operating expenses for the quarter and six months ended June 30, 2014. We expect to replace most, if not all, of the contract laborers with full time employees which, in turn, is expected to bring down our associated lease operating expenses. As a result of hiring at the professional staff level and certain severance payments, we experienced a rise in compensation expense for the period and will experience a further rise in compensation expense as we transition in new field personnel to replace contract labor.

Share Issuances for Cash

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

Hedging Activities

As of June 30, 2014, we had in place fixed price swaps covering an aggregate of 23,000 barrels of oil over the period beginning July 1, 2014 and ending September 30, 2014, at a price of $106.95 per barrel.

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 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.

Results of Operations

Oil and Gas Revenue

Oil and gas revenue for the quarter ended June 30, 2014 decreased by 14.7% to $15.1 million from $17.7 million in the 2013 quarter. For the six month period ended June 30, 2014 oil and gas revenue decreased by 30.5% to $25.7 million from $37.0 million in the 2013 period.

For the quarter ended June 30, 2014, the decrease in revenue was attributable to a 12.5% decline in oil revenues on a 12.3% decrease in oil production volumes with average oil prices realized essentially remaining flat and a 33.5% decline in gas revenues on a 41.2% decrease in gas production volumes partially offset by a 12.9% increase in average prices realized, each as compared to the 2013 quarter. For the six months ended June 30, 2014, the decrease in revenue was attributable to a 29.1% decline in oil revenues on a 26.2% decrease in oil production volumes and a 3.8% decrease in average oil prices realized and a 42.6% decline in gas revenues on a 53.5% decrease in gas production volumes partially offset by a 23.7% 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 six months ended June 30, 2014 and 2013:

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Revenues				
Oil	$ 13,860,254	$ 15,831,909	$ 23,561,096	$ 33,220,809
Gas	1,260,463	1,895,848	2,162,612	3,768,849
Total oil and gas revenues	$ 15,120,717	$ 17,727,757	$ 25,723,708	$ 36,989,658
Production				
Oil (Bbls)	134,769	153,753	229,016	310,523
Gas (Mcf)	253,025	430,381	405,886	873,727
Total production (Boe)	176,940	225,483	296,664	456,144
Average sales price				
Oil (per Bbl)	$ 102.84	$ 102.97	$ 102.88	$ 106.98
Gas (per Mcf)	4.98	4.41	5.33	4.31
Total average sales price (per Boe)	$ 85.46	$ 78.62	$ 86.71	$ 81.09

Oil production was down 19.0 MBbl, or 12.3%, and 81.5 MBbl or 26.2% for the quarter and six months ended June 30, 2014, respectively, as compared to the same period in 2013.

The decrease in oil production during the 2014 quarter and six month period reflected a combination of reduced run times (as discussed above), particularly in the earlier months of 2014, elevated decline rates in certain high production wells, and increased water-cut in selected wells, gas lift gas shortages, mechanical issues and flow line capacity constraints (discussed above), 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 quarter were principally in Breton Sound 18 (down 20.3 Mbbl), Main Pass 46 (down 10.4 Mbbl) and Grand Bay (down 14.8 Mbbl). In Breton Sound 18 Field, the decline in oil production reflected elevated decline rates and increased water-cut in the North Tiger dually-completed well as it was coming off peak rates from its initial production in late 2012 and facility and compressor related issues. At Main Pass 46, the decline in oil production reflected lower production from the Catina well as a result of natural decline and shut-ins for flow line and compressor repairs. At Grand Bay, the decline in oil production reflected curtailment of one well to limit sand production, decreased production due to natural decline and increased water-cut in another well, and depletion and/or mechanical failure in an additional dually-completed well. The decrease in oil production in Grand Bay field was partially offset by increased production from a number of wells that underwent recompletion or workover projects during the first half of 2014. The declines for the quarter 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 our Zeke (6.9 Mbbl increase), and Rocky wells (12.1 Mbbl increase) during 2013, and Rocky 3 (12.4 Mbbl increase) during 2014.

Natural gas production was down 177.4 MMcf, or 41.2%, and 467.8 MMcf, or 53.5%, for the quarter and six months ended June 30, 2014, respectively, as compared to the same periods in 2013.

The decrease in gas production during the 2014 quarter and six 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 quarter were principally in Grand Bay (down 185 MMcf), Main Pass 52 (down 19 MMcf) and Main Pass 25 (down 9 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, the decline in gas production reflected the depletion of a long-time gas producer during the second quarter 2013 and downhole conditions in a well. Partially offsetting the decreases were gas-targeted recompletions at Grand Bay, Breton Sound 32, and Main Pass 46, which collectively added 78 MMcf and 101 MMcf of gas production for the quarter and six-month periods ended June 30, 2014 compared to the same periods in 2013.

As noted above, by quarter end or shortly thereafter, run-time issues, flow line capacity restrictions and certain mechanical and facilities issues that contributed to declines in oil and gas production had been addressed in part or in whole and production rates have risen over the quarter ended June 30, 2014 and following quarter end.

The increase in realized hydrocarbon prices reflects a general strengthening of natural gas prices, partially offset by a moderation in crude oil prices. We continue to receive a premium pricing on both our crude oil and natural gas production.

Other Revenues

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

Operating Expenses

Operating expenses decreased by 8.5% to $15.6 million for the quarter ended June 30, 2014 from $17.0 million in the 2013 quarter. The following table sets forth the components of operating expenses for the 2014 and 2013 quarters:

	Three Months Ended June 30, 2014		Three Months Ended June 30, 2013	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 6,304,457	$ 35.63	$ 5,200,113	$ 23.06
Workover expense	107,582	0.61	1,167,870	5.18
Exploration expense	200,298	1.13	115,687	0.51
Depreciation, depletion and amortization	4,507,996	25.48	5,662,542	25.11
Accretion expense	448,467	2.54	638,097	2.83
General and administrative	2,702,388	15.27	2,335,208	10.36
Severance taxes	1,309,592	7.40	1,901,558	8.43
	$ 15,580,780	$ 88.06	$ 17,021,075	$ 75.48

Operating expenses decreased by 8.0% to $29.5 million for the six months ended June 30, 2014 from $32.1 million in the 2013 period. The following table sets forth the components of operating expenses for the 2014 and 2013 periods:

	Six Months Ended June 30, 2014		Six Months Ended June 30, 2013	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 11,797,272	$ 39.77	$ 9,803,154	$ 21.49
Workover expense	2,299,768	7.75	1,429,132	3.14
Exploration expense	421,650	1.42	283,971	0.62
Depreciation, depletion and amortization	7,250,055	24.44	10,871,036	23.83
Accretion expense	896,933	3.02	1,276,194	2.80
General and administrative	5,054,958	17.04	4,438,742	9.73
Severance taxes	1,810,342	6.10	3,992,612	8.75
	$ 29,530,978	$ 99.54	$ 32,094,841	$ 70.36

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

Lease Operating Expense

Lease operating expenses for the quarter ended June 30, 2014 increased 21.2%, to $6.3 million, from $5.2 million in the 2013 quarter and 20.3% for the six months ended June 30, 2014, to $11.8 million, from $9.8 million in the 2013 period. The increase in lease operating expense for the six months ended June 30, 2014 was primarily due to (i) increased contract construction labor costs incurred in Main Pass 25/46, Breton Sound and Grand Bay Fields; (ii) contract construction labor and building repair and maintenance expenses for living quarters in Grand Bay Field; (iii) higher contract pumping costs in Breton Sound, Main Pass 25 and Grand Bay Fields for services provided to replace reduced field personnel as part of first quarter 2014 initiative to increase operational efficiencies; (iv) increase in equipment rental expense for Breton Sound 32 and Grand Bay Fields; (v) increased platform/flow lines repair and maintenance expenses in Main Pass 25/46 and Breton Sound 18/32 Fields; and (v) a Breton Sound 32 flow line well maintenance charge in March of 2014. An estimated $0.9 million of the increase in lease operating expense related to contract construction labor, building repairs and maintenance, and well maintenance charges that were associated with our production enhancement initiative. We will additionally 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 and contract labor expenses were partially offset by decreases in slickline operations and payroll/payroll burden 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 due to the need for marine transportation in the shallow water, bay environment. The increase in lease operating expenses on a per BOE basis for the quarter was primarily attributable to the decreases in production volumes and the fixed nature of certain lease operating expenses.

Workover Expense

Workover expense for the quarter ended June 30, 2014 decreased to $107,582 from $1,167,870 in the 2013 quarter and increased to $2,299,768 from $1,429,132 for the six months ended June 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 June 30, 2014 increased to $200,298 from $115,687 in the 2013 quarter. Exploration expense for the six months ended June 30, 2014 increased to $421,650 from $283,971 in the 2013 period. The increase in exploration expenses was principally due to investment in field studies related to our Gulf of Mexico shelf acreage.

Depreciation, Depletion and Amortization (DD&A)

Depreciation, depletion and amortization for the quarter ended June 30, 2014 decreased 20.4% to $4,507,996 from $5,662,542 in the 2013 quarter and increased to $25.48 per BOE from $25.11 per BOE in the 2013 quarter. Depreciation, depletion and amortization for the six months ended June 30, 2014 decreased 33.3% to $7,250,055 from $10,871,036 in the 2013 period and increased to $24.44 per BOE from $23.83 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 2014 periods was primarily attributable to production declines as compared to the 2013 periods.

Accretion expense

Accretion expense relating to our asset retirement obligations decreased to $448,467 from $638,097 for the quarter ended June 30, 2014 as compared to the 2013 quarter and decreased to $896,933 from $1,276,194 for the six months ended June 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 June 30, 2014 increased 15.7% to $2,702,388 as compared to $2,335,208 in the 2013 quarter, and increased 13.9% for the six months ended June 30, 2014 to $5,054,958 as compared to $4,438,742 in the 2013 period. The increase in G&A expense for the quarter was primarily due to increased legal and professional fees and an increase in the employee headcount resulting in higher salaries and benefits, partially offset by a decrease in non-cash stock compensation expense.

Severance Taxes

Severance taxes for the quarter ended June 30, 2014 decreased to $1,309,592 from $1,901,558 in the 2013 quarter and decreased to $1,810,342 for the six months ended June 30, 2014 from $3,992,612 for the 2013 period. The decrease was primarily attributable to production declines and the horizontal well severance tax exemptions obtained for our Rocky and Zeke wells and the deep well severance tax exemption obtained for our Mesa Verde well. These exemptions resulted in refunds of severance taxes paid in prior periods of $0.5 million.

Other Income (Expense), Net

Net other expense increased to $6.0 million in for the quarter ended June 30, 2014 from $5.3 million for the 2013 quarter and increased to $12.0 million for the six months ended June 30, 2014 from $10.5 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 June 30, 2014 we recorded an income tax expense of $40,199 compared to a benefit of $1,059,382 during the 2013 quarter. For the six months ended June 30, 2014 we recorded an income tax expense of $122,265 compared to a benefit of $1,513,532 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.

We believe that our cash flows from operations and cash on hand are sufficient to support our liquidity needs for the next twelve months, including funding all of our current short-term objectives, including investments in planned infrastructure and deferred maintenance, recompletions, workovers and through-tubing plugbacks. We believe that our cash flows from operations and cash on hand will also be sufficient to pursue our current mid-term objectives relating to development of proved undeveloped opportunities. Our development of proved undeveloped opportunities is scalable. Depending upon operating results, including the results of our short-term development initiatives, ongoing development efforts relating to our proved undeveloped opportunities and any further capital commitments, we may accelerate or curtail our planned development of proved undeveloped opportunities or otherwise adjust the nature or rate of our development program to reflect available funding.

Pursuit of our long-term plans for exploratory drilling of deep shelf prospects in Grand Bay Field, Vermilion 16 Field and our newly acquired Gulf of Mexico shelf prospects is expected to require funding in excess of our current resources and projected operating cash flow and, with respect to ultra-deep prospects in Vermilion 16 Field, to be dependent upon results attained by other operators that are currently pioneering ultra-deep drilling in the trend within which our ultra-deep prospects are located. During the six months ended June 30, 2014, we devoted internal and outside resources to preparation of comprehensive geological, engineering, marketing and related materials to commence a professional marketing program for presentation to prospective joint venture partners on both our Gulf of Mexico and Grand Bay deep prospects. Following quarter end, we completed pre-marketing efforts and commenced our formal marketing program to prospective participants in the first of our Grand Bay deep prospects. We anticipate commencement of a similar formal marketing program to prospective participants in our Gulf of Mexico prospects during the second half of 2014. Subject to securing required commitments of financial partners, we are targeting commencement of drilling on our Grand Bay deep shelf and Gulf of Mexico prospects in 2015. We presently have no commitments to provide funding to support development of our deep prospects and there is no assurance that such funding will be available or that we will be able to fund our share of any such costs.

Unexpected declines in commodity prices or production levels, or failures in achieving production increases through short- and mid-term development plans, could result in our inability to support our operations and drilling and development plans.

Cash, Cash Flows and Working Capital

We had a cash balance of $18.4 million and working capital of $4.6 million at June 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 the interest payment on our 12.5% Second Line Notes in January 2014 and on our 10% First Lien Notes in June 2014 and to reductions in operating cash flow and investments in our development program. The decrease in our working capital was primarily attributable to the reduction in our cash balance.

Operations used cash flow of $7.3 million for the six months ended June 30, 2014 as compared to providing $10.7 million for the six months ended June 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 $6.5 million during the six months ended June 30, 2014 as compared to $12.3 million used during 2013. The decrease in cash used in investing activities was primarily due a reduction in developmental wells drilled during the period.

Financing activities used cash flows of $0.5 million during the six months ended June 30, 2014 and 2013. Cash flows used by financing activities during both periods primarily related to repayments on our short-term notes payable.

Debt

At June 30, 2014, we had $178.5 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 $1.1 million of debt discount.

We had no letters of credit outstanding at June 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 and Commitments

Our capital spending for the six months ended June 30, 2014 was $12.7 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), nine workovers ($2.3 million), investments in multiple infrastructure projects ($1.0 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 and associated revenues and cash position accompanying the drop in run times during January and February, and the rebound in our run times and production levels beginning in March 2014, we presently expect to focus our efforts during the third quarter of 2014 on recompletions and workovers that have the potential to enhance production in a short time frame and at lower cost in order to build our cash position with a view to pursuing renewed development drilling beginning in the fourth quarter of 2014 or the first quarter of 2015.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at June 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 June 30, 2014, we had the following hedge contracts outstanding:

Instrument	Beginning Date	Ending Date	Fixed Price	Strike Price	Premium	Total Bbls
Fixed Price Swap	July 1, 2014	September 30, 2014	$ 106.95	$ -	$ -	23,000
Covered Call	April 1, 2014	March 31, 2015	$ -	$ 103.30	$ 6.80	68,500
						91,500

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. For the three and six months ended June 30, 2014, we recorded unrealized losses on commodity derivatives of $112,804 and $12,451, respectively, in accumulated other comprehensive income (loss).

Koch Supply & Trading, LP is the counterparty to our present fixed price swap contracts and covered call options. 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 June 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 June 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 March 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II

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: August 14, 2014		
	By:	/s/ Thomas Cooke Thomas Cooke Chief Executive Officer
	By:	/s/ John Ebert John Ebert Vice President Finance and Business Development