Armada Oil, Inc.
Form 10-Q
November 14, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2013

or

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

For the Transition Period from _________ to _________

Commission file number: 333-52040

ARMADA OIL, INC.
(Exact name of registrant as specified in its charter)

Nevada	98-0195748
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5220 Spring Valley Road, Suite 615
Dallas, Texas 75254
(Address of principal executive offices) (zip code)

(972) 490-9595
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 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 ¨ No ¨ (Note: The registrant is a voluntary filer of reports under Section 13 or 15(d) of the Securities Exchange Act of 1934; the registrant has filed during the preceding 12 months all reports it would have been required to file by Section 13 or 15(d) of the Securities Exchange Act of 1934 if the registrant had been subject to one of such Sections.)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

As of November 11, 2013, there were 56,030,473 shares of the registrant's common stock outstanding.

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ARMADA OIL, INC.

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PART 1. FINANCIAL INFORMATION

Item 1. Interim Consolidated Financial Statements

ARMADA OIL, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,011,331	$ 5,884,649
Accounts receivable – oil and gas	1,944,064	1,593,258
Accounts receivable – other	83,315	280,430
Derivative asset, commodity contracts – current	—	83,298
Deferred financing costs, net – current	18,802	22,563
Deferred tax asset – current	100,606	38,325
Prepaid expenses	235,827	117,678
TOTAL CURRENT ASSETS	3,393,945	8,020,201
Oil and gas properties, successful efforts accounting:		
Properties subject to amortization, net	8,134,789	9,082,526
Properties not subject to amortization	10,711,770	759,133
Support facilities and equipment, net	1,838,396	2,075,563
Land	48,345	48,345
Net oil and gas properties	20,733,300	11,965,567
Property and equipment, net	215,134	241,627
Deferred financing cost, net – noncurrent	—	13,162
Deferred tax asset – noncurrent	11,910,689	3,126,478
Deposit on asset retirement obligations	585,973	609,421
Other assets	55,598	4,013
TOTAL ASSETS	$ 36,894,639	$ 23,980,469
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable – trade	$ 635,519	$ 1,045,918
Revenue payable	472,316	334,433
Accrued expenses	679,012	753,961
Accrued expenses – related parties	16,457	54,840
Notes payable, net – current	8,933,981	90,417
Notes payable – related parties, net – current	90,751	—
Derivative liability, commodity contracts - current	291,924	—
Other current liabilities	—	91,000
TOTAL CURRENT LIABILITIES	11,119,960	2,370,569
Notes payable, net – noncurrent	—	9,195,963
Derivative liability, commodity contracts – noncurrent	138,856	58,519

Deferred tax liability – noncurrent		247,910		678,782
Asset retirement obligations		3,736,435		3,507,798
TOTAL LIABILITIES		15,243,161		15,811,631
Commitments and contingencies				
Stockholders' equity:				
Common stock, par value $0.001, 100,000,000 shares authorized, 56,030,473 and 33,732,191 shares issued and outstanding, respectively		56,030		33,732
Additional paid-in capital		16,007,614		803,974
Retained earnings		5,587,834		7,331,132
TOTAL STOCKHOLDERS' EQUITY		21,651,478		8,168,838
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$	36,894,639	$	23,980,469

See accompanying notes to unaudited consolidated financial statements.

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ARMADA OIL, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Revenues	$ 3,302,121	$ 3,235,366	$ 9,846,067	$ 11,477,268
Operating expenses:				
Lease operating expense	1,621,231	1,548,851	5,888,841	5,171,819
Environmental remediation expense	—	—	—	244,237
Exploration cost	179,517	137,090	271,863	233,089
Dry hole expense	—	—	2,609,866	—
Depletion, depreciation, amortization, accretion and impairment	522,933	361,484	1,554,062	1,215,448
Loss on sale of oil and gas properties	55,448	—	55,448	—
(Gain) loss on settlement of asset retirement obligations	—	—	(1,328)	116,394
General and administrative expense	798,862	834,953	3,401,724	2,542,226
Total operating expense	3,177,991	2,882,378	13,780,476	9,523,213
Income (loss) from operations	124,130	352,988	(3,934,409)	1,954,055
Other income (expense):				
Interest income	—	1,991	4,468	7,789
Interest expense	(252,425)	(143,940)	(649,655)	(418,078)
Realized gain on commodity contracts	101,409	117,741	252,146	363,733
Loss on change in derivative value – commodity contracts	(507,389)	(862,306)	(455,561)	(938,606)
Loss on change in derivative value – conversion feature	—	(17,714)	—	(536,422)
Loss on modification of offering	—	—	(65,749)	—
Bargain purchase gain	—	—	1,455,879	—
Other income (expense)	(12,600)	(1,485)	11,991	4,380
Total other expense	(671,005)	(905,713)	553,519	(1,517,204)
Net income (loss) before income taxes	(546,875)	(552,725)	(3,380,890)	436,851
Income tax benefit (expense)	349,663	195,850	1,637,592	(272,164)
Net income (loss)	$ (197,212)	$ (356,875)	$ (1,743,298)	$ 164,687
Net income (loss) per common share:				
Basic	$ (0.00)	$ (0.01)	$ (0.04)	$ 0.01
Diluted	$ (0.00)	$ (0.01)	$ (0.04)	$ 0.01
Weighted average number of common shares outstanding:				
Basic	56,030,473	33,936,688	48,966,471	33,484,800

Diluted	56,030,473	33,936,688	48,966,471	34,188,680

See accompanying notes to these unaudited consolidated financial statements.

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ARMADA OIL, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (1,743,298)	$ 164,687
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion, amortization, accretion and impairment	1,554,062	1,215,448
Dry hole expense	2,609,866	—
Deferred income taxes	(1,637,592)	272,164
Share-based compensation	636,714	273,478
Loss on sale of oil and gas property	55,448	—
(Gain) loss on settlement of asset retirement obligations	(1,328)	116,394
Amortization of debt discount charged to interest expense	105,789	4,279
Amortization of deferred financing costs	16,923	38,573
Realized gain on derivative commodity contracts	(252,146)	(363,733)
Unrealized gain on change in derivative value – commodity contracts	455,561	938,606
Gain on change in derivative value – conversion feature	—	536,422
Bargain purchase gain	(1,455,879)	—
Loss on offering modification	65,749	—
Changes in operating assets and liabilities:		
Accounts receivable – oil and gas	(350,806)	627,905
Accounts receivable – other	197,115	(99,001)
Prepaid expenses	66,240	(263,294)
Accounts payable and accrued expenses	(431,693)	(855,717)
Accrued expenses – related parties	(38,383)	—
Revenue payable	137,883	(235,291)
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	(9,775)	2,370,920
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid for acquisition and development of oil and gas properties	(2,837,548)	(2,024,024)
Cash received for sale of oil and gas properties	85,000	—
Cash received for sale of support facilities and equipment	54,018	—
Cash paid for support facilities and equipment	(92,094)	(249,993)
Cash paid to settle asset retirement obligation for oil and gas properties	—	(255,751)
Cash proceeds from settlement of derivative commodity contracts	252,146	363,733
Cash paid for acquisition of Armada	(293,106)	—
Cash paid for property and equipment	(8,844)	(67,710)
CASH USED IN INVESTING ACTIVITIES	(2,840,428)	(2,233,745)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings on debt, net of financing costs	305,515	11,224
Proceeds from borrowings on debt – related parties, net of financing costs	135,000	—
Principal repayments on debt	(2,372,630)	(461,731)

Installment payments on software		(91,000)		(11,375)
CASH USED IN FINANCING ACTIVITIES		(2,023,115)		(461,882)
NET CHANGE IN CASH		(4,873,318)		(324,707)
CASH AT BEGINNING OF PERIOD		5,884,649		3,182,392
CASH AT END OF PERIOD	$	1,011,331	$	2,857,685
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION				
Cash paid for interest	$	454,331	$	346,345
Cash paid for income taxes	$	75,000	$	37,000
NON-CASH INVESTING AND FINANCING TRANSACTIONS				
Settlement of derivative liability from conversion of debt	$	—	$	649,505
Common stock issued for the conversion of notes payable and accrued interest	$	—	$	466,019
Common stock issued in satisfaction of stock payable	$	325,000	$	—
Debt discount related to warrants issued in conjunction with notes payable and notes payable – related parties	$	142,133	$	—
Increase in fair value of asset retirement obligations	$	30,716	$	—
Common stock issued for purchase of Armada	$	14,056,342	$	—
Software purchased with installment payments	$	—	$	136,500
Prepaid insurance financed with a note payable	$	129,465	$	89,631

See accompanying notes to these unaudited consolidated financial statements.

ARMADA OIL, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1 – ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Organization

Armada Oil, Inc. (the “Company”, “Armada”, or “we”) was incorporated under the laws of the State of Nevada on November 6, 1998, under the name “e.Deal.net, Inc.” On June 20, 2005, the Company amended its Articles of Incorporation to effect a change of name to International Energy, Inc. On June 27, 2011, the Company amended its Articles of Incorporation to change its name to NDB Energy, Inc. On May 7, 2012, the Company filed a Certificate of Amendment to its Articles of Incorporation to change its name to Armada Oil, Inc.

On March 28, 2013 Armada completed a business combination with Mesa Energy Holdings, Inc. (“Mesa”), pursuant to which Armada acquired from Mesa substantially all of the assets of Mesa consisting of all of the issued and outstanding shares of Mesa Energy, Inc. (“MEI”), whose predecessor entity, Mesa Energy, LLC, was formed in April 2003 as an exploration and production company in the oil and gas industry. Although Armada was the legal acquirer, Mesa was the accounting acquirer.

MEI’s oil and gas operations are conducted through itself and its wholly owned subsidiaries. MEI acquired Tchefuncte Natural Resources, LLC (“TNR”) in July 2011. TNR owns interests in 80 wells and related surface production equipment in five fields located in Plaquemines and Lafourche Parishes, Louisiana. Mesa Gulf Coast, LLC (“MGC”) became the operator of all operated properties in Louisiana in October 2011. Mesa Midcontinent, LLC is a qualified operator in the state of Oklahoma and operates our properties in Garfield and Major Counties, Oklahoma. MEI is a qualified operator in the State of New York and operates the Java Field.

The Company’s operating entities have historically employed, and will continue in the future to employ, on an as-needed basis, the services of drilling contractors, other drilling related vendors, field service companies and professional petroleum engineers, geologists and landmen as required in connection with future drilling and production operations.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements have been prepared by the Company in accordance with accounting principles generally accepted in the United States of America and the rules of the Securities and Exchange Commission (“SEC”). and should be read in conjunction with the audited consolidated financial statements and notes thereto contained in the Company’s latest annual report filed with the SEC on Form 10-K. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for a fair presentation of financial position and the results of operations for the interim periods presented have been reflected herein. The results of operations for interim periods are not necessarily indicative of the results to be expected for the full year. Notes to the unaudited interim consolidated financial statements that would substantially duplicate the disclosures contained in the audited consolidated financial statements for fiscal year 2012, as reported in the Form 10-K, have been omitted.

Principles of Consolidation

The consolidated financial statements include the Company’s accounts and those of the Company’s wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year and the reported amount of proved natural gas and oil reserves. Management bases its estimates on historical experience and various other assumptions that it believes are reasonable under the circumstances, the results of which form the basis for making judgments that are not readily apparent from other sources. Actual results could differ from these estimates and changes in these estimates are recorded when known.

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Reclassifications

Certain reclassifications have been made to amounts in prior periods to conform to the current period presentation. All reclassifications have been applied consistently to the periods presented.

Earnings Per Common Share

The Company's earnings per share are computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflects the potential dilution of securities, if any, that could share in the earnings of the Company and is calculated by dividing net income by the diluted weighted average number of common shares. The diluted weighted average number of common shares is computed using the treasury stock method for common stock that may be issued for outstanding stock options and convertible debt.

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Numerator:				
Net income (loss) available to stockholders	$ (197,212)	$ (356,875)	$ (1,743,298)	$ 164,687
Basic net income allocable to participating securities (1)	—	—	—	(3,230)
Basic net income (loss) available to stockholders	(197,212)	(356,875)	(1,743,298)	161,457
Impact of assumed conversions-interest expense, net of income taxes	N/A	—	N/A	11, 359
Loss available to stockholders assuming conversion of convertible debentures	$ N/A	$ (356,875)	$ N/A	$ 172,816
Denominator:				
Weighted average number of common shares – Basic	56,030,473	33,936,688	48,966,471	33,484,800
Effect of dilutive securities (2) :				
Options and warrants	—	—	—	108,664
Convertible promissory notes	N/A	—	N/A	595,215
Weighted average number of common shares – Diluted	56,030,473	33,936,688	48,966,471	34,188,680
Net income (loss) per common share:				
Basic	$ (0.00)	$ (0.01)	$ (0.04)	$ 0.01
Diluted	$ (0.00)	$ (0.01)	$ (0.04)	$ 0.01

(1) Restricted share awards that contain nonforfeitable rights to dividends are participating securities and, therefore, are included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses.

(2) For the three and nine months ended September 30, 2013, stock options and warrants representing 2,806,000 and 8,728,118 shares, respectively were out of the money, antidilutive and, therefore, excluded from the diluted share calculation. For the three months ended September 30, 2012, out of the money stock options and warrants representing 561,200 and 200,000 shares, respectively, were antidilutive and excluded from the diluted share calculation. No shares associated with the Company's convertible promissory notes were excluded from the

diluted share calculations for the nine months ended September 30, 2012.

Recently Issued Accounting Pronouncements

The Company does not expect the adoption of any recently issued accounting pronouncements to have a significant impact on its financial position, results of operations or cash flows.

Subsequent Events

The Company has evaluated all transactions through the financial statement issuance date for subsequent event disclosure consideration.

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NOTE 2 – BUSINESS COMBINATION

On March 28, 2013, Armada completed the acquisition (the “Acquisition”) of substantially all of the assets of Mesa Energy Holdings, Inc. consisting of all of the issued and outstanding shares of MEI pursuant to the terms of the Asset Purchase Agreement and Plan of Reorganization Among Armada Oil, Inc., Mesa Energy Holdings, Inc., and Mesa Energy, Inc. (the “APA”). The Company accounted for the assets, liabilities and ownership interests in accordance with the provisions of ASC 805, Business Combinations for acquisitions occurring in years beginning after December 15, 2008 (formerly SFAS No. 141R, Business Combinations).

Armada acquired MEI, with Mesa continuing as the accounting acquirer and becoming a wholly-owned subsidiary of Armada, in a transaction structured to qualify as a tax-free reorganization. In connection with the Acquisition, Armada issued former security holders of Mesa 21,475,284 shares of common stock and paid a consultant who worked with us in effecting the Acquisition $325,000. The Company also assumed a liability to issue the consultant stock valued at $325,000. The equity instruments issued in the Acquisition had a fair value of $14,056,342 as of the date of the Acquisition.

The Acquisition was accounted for as a “reverse acquisition,” and Mesa was deemed to be the accounting acquirer in the Acquisition. Armada’s assets and liabilities were recorded at their fair value. MEI’s assets and liabilities were carried forward at their historical cost. The financial statements of Mesa are presented as the continuing accounting entity since it is the acquirer for the purpose of applying purchase accounting. The equity section of the balance sheet and earnings per share of Mesa are retroactively restated to reflect the effect of the exchange ratio established in the APA.

The acquisition price was allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition.

Assets acquired:	
Cash	$ 31,894
Prepaid assets	33,061
Other current assets	50,000
Total current assets	114,955
Oil and gas properties, subject to amortization	514,249
Oil and gas properties, not subject to amortization	9,948,551
Deferred tax asset	7,993,591
Total assets acquired	18,571,346
Liabilities assumed:	
Accounts payable and accrued liabilities	2,471,665
Note payable, net of discount of $103,001	197,197
Asset retirement obligations	65,263
Total liabilities assumed	2,734,125
Net assets acquired	$ 15,837,221
Bargain purchase gain	(1,455,879)
Consideration paid – cash and equity instruments at fair value	$ 14,381,342

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Pro forma results of operations for the nine month periods ended September 30, 2013 and 2012, as though this acquisition had taken place at the beginning of each period, are as follows. The pro forma results are not necessarily indicative of what actually would have occurred had the acquisition been in effect for the entire period presented.

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues	$ 9,952,873	$ 11,565,100
Net income (loss)	$ (3,825,883)	$ (821,282)
Income (loss) per common share:		
Basic	$ (0.08)	$ (0.02)
Diluted	$ (0.08)	$ (0.02)
Weighted average common shares outstanding		
Basic	48,966,471	51,135,137
Diluted	48,966,471	51,135,137

NOTE 3 – FAIR VALUE MEASUREMENTS

The following tables set forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012.

September 30, 2013	Carrying Value	Fair Value Measurement Level 1	Fair Value Measurement Level 2	Fair Value Measurement Level 3
Derivative asset – commodity contracts	$ —	$ —	$ —	$ —
Derivative liability – commodity contracts	(430,780)	—	(430,780)	—

December 31, 2012	Carrying Value	Fair Value Measurement Level 1	Fair Value Measurement Level 2	Fair Value Measurement Level 3
Derivative assets – commodity contracts	$ 83,298	$ —	$ 83,298	$ —
Derivative liability – commodity contracts	$ (58,519)	$ —	$ (58,519)	$ —

The Company did not identify any other assets and liabilities that are required to be presented on the consolidated balance sheet at fair value.

NOTE 4 – COMMODITY DERIVATIVE INSTRUMENTS

The Company engages in price risk management activities from time to time, through utilizing derivative instruments consisting of swaps, floors and collars, to attempt to reduce the Company’s exposure to changes in commodity prices. None of the Company’s derivatives is designated as a cash flow hedge. Changes in fair value of derivative instruments which are not designated as cash flow hedges are recorded in other income (expense) as realized and unrealized (gain) loss on commodity derivatives.

While the use of these arrangements may limit the Company's ability to benefit from increases in the price of oil and natural gas, it serves to reduce the Company's potential exposure to significant price declines. These derivative transactions are generally placed with major financial institutions that the Company believes are financially stable; however, there can be no assurance of the foregoing.

The Company has commodity derivative instruments with a single counterparty for which it determined the fair value using period-end and future oil and gas prices, interest rates and volatility factors for the periods under each contract as of September 30, 2013 and 2012.

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The details of the commodity derivatives at September 30, 2013, are summarized below:

Costless Gas Collar

Production Period	Total Volumes	Weighted Average Floor/Ceiling	Fair Value
Oct 2013-Dec 2013 (1)	75,000 MMBtu	$ 2.50 / 3.50	$ (21,945)
Jan 2014-Oct 2014 (3)	130,000 MMBtu	$ 3.75 / 4.25	$ 13,434
Nov 2014-Dec 2014 (3)	26,000 MMBtu	$ 3.75 / 4.50	$ (1,385)

Oil Fixed Price Swaps

Production Period	Total Volumes	Average Fixed Price	Fair Value
Jan 2014-Dec 2014 (3)	60,000 Bbls	$ 95.75	$ (244,330)
Jan 2015-Mar 2015 (3)	11,049 Bbls	$ 92.50	$ (30,644)
Apr 2015-Dec 2015 (6)	31,500 Bbls	$ 89.50	$ (93,797)

Average Price Oil Collar

Production Period (4)	Total Volume	Average Floor / Ceiling	Fair Value
Oct 2013-Dec 2013 (2)	20,454 Bbls	$ 80 / 100	$ (74,043)

Oil Basis Swap

Production Period	Total Volume	Basis Price	Fair Value
Jan 2014-Dec 2014 (5)	60,000 Bbls	$ 4.85	$ 21,930

(1) Costless gas collar entered into on June 26, 2012.
(2) Average price collar entered into on July 19, 2012.
(3) Costless gas collar and oil fixed price swap entered into on March 8, 2013.
(4) On March 8, 2013, the Company unwound the crude oil average price collar for the January 2014 through July 2014 settlements periods. Volumes unwound were 39,424 bbls with a fixed price of $100 per bbl. The Company incurred a loss of $8,144 in unwinding these positions.
(5) On July 15, 2013, the Company unwound its basis swaps covering 40,800 Bbls of oil for settlement periods July 2013 through December 2013 and realized a gain of $146,540 on the transaction. On the same date, the Company entered into new basis swaps covering

60,000 Bbls of oil over monthly settlement periods of 5,000 Bbls from January 2014 through December 2014. The basis differential is $4.85/Bbl between Louisiana Light Sweet Crude Oil and NYMEX Light Sweet Crude Oil.

(6) September 30, 2013, fixed oil price swap.

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At September 30, 2013, the Company had current and noncurrent derivative assets of $0 and current and noncurrent derivative liabilities of $291,924 and $138,856, respectively, with the $507,389 and $455,561 decrease in fair value reported in other income as unrealized loss on derivative instruments for the three and nine months ended September 30, 2013, respectively. Realized gains of $101,409 and $252,146 for the three and nine months ended September 30, 2013, respectively, from settlements of these derivatives have been reported in other income as realized gain on commodity contracts.

The details of the commodity derivatives at September 30, 2012, are summarized below:

Costless Gas Collars

Production Period	Total Volume	Average Floor / Ceiling	Fair Value
Sep 2012-Dec 2012(1)	132,000 MMBtu	$ 2.50/ 3.50	$ (32,613)
Jan 2013-Dec 2013(1)	230,000 MMBtu	$ 2.50/ 4.50	$ (45,770)

Gas Fixed Price Swaps

Production Period	Total Volume	Average Fixed Price	Fair Value
Oct 2012-Dec 2012 (3)	3,000 Bbls	$ 100.30	$ 22,689
Oct 2012-Dec 2012	10,500 Bbls	$ 114.50	$ 46,065
Jan 2013-Jul 2013	18,900 Bbls	$ 114.90	$ 169,450

Oil Fixed Price Swaps

Production Period	Total Volume	Average Floor / Ceiling	Fair Value
Oct 2012-Jan 2013(4)	14,175 Bbls	$ 80/ 100	$ (4,205)
Jan 2013-Feb 2013	6,525 Bbls	$ 80/ 100	$ (7,634)
Feb 2013-Aug 2013	24,708 Bbls	$ 80/ 100	$ (41,056)
Aug 2013-Feb 2014	40,908 Bbls	$ 80/ 100	$ (93,155)
Feb 2014-Jul 2014	39,424 Bbls	$ 80/ 100	$ (48,435)

(1) Costless gas collar entered into on June 26, 2012.
(2) Fixed price swap is the remaining put of July 25, 2011 costless gas collar unwound on June 26, 2012.
(3) Crude oil swap entered into on January 6, 2012.
(4) Average price collar entered into on July 19, 2012.

At September 30, 2012, the Company recognized a short-term derivative asset of $111,300, a short term derivative liability of $0, and a long-term derivative liability of $112,164, with the $862,306 decrease in fair value reported in other income (expense) as unrealized loss on derivative instruments for the three months ended September 30, 2012 and a $938,606 decrease in fair value reported in other income (expense) as an unrealized loss on derivative instruments for the nine months ended September 30, 2012. Net realized gains of $117,741 and $363,733 from settlements of these derivatives have been reported in other income (expense) as realized gain on commodity contracts during the three and nine months ended September 30, 2012, respectively.

NOTE 5 – PROPERTY AND EQUIPMENT

Oil and Gas Properties

The Company's oil and gas properties at September 30, 2013 are located in the United States of America.

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The carrying values of the Company's oil and gas properties, net of depletion and impairment, at September 30, 2013 and December 31, 2012 were:

Property	September 30, 2013	December 31, 2012
Lake Hermitage Field	$ 3,769,687	$ 3,568,957
Valentine Field	1,705,170	1,995,406
Larose Field	1,323,710	1,435,549
Bay Batiste Field	1,015,637	1,050,390
Turkey Creek Field	855,865	1,791,357
Keller Prospect	225,390	—
Bear Creek Prospect	9,951,100	—
Total	$ 18,846,559	$ 9,841,659

Net oil and gas properties at September 30, 2013 were:

Year Incurred	Acquisition Costs	Exploration and Development Costs	Dry Hole Costs	Disposition of Assets	Depletion, Amortization, and Impairment	Total
2011 and prior	$ 8,089,062	$ 3,553,607	$ (466,066)	$ (2,090,383)	$ (2,359,193)	$ 6,727,027
2012	759,133	3,807,248	—	—	(1,451,749)	3,114,632
2013	9,952,645	2,915,791	(2,609,866)	(121,993)	(1,131,677)	9,004,900
Total	$ 18,800,830	$ 10,276,646	$ (3,075,932)	$ (2,212,376)	$ (4,942,619)	$ 18,846,559

Lake Hermitage Field – Plaquemines Parish, Louisiana

In the nine months ended September 30, 2013, the Company spent $676,555 on development of the Lake Hermitage field which included expenditures as detailed on the following table.

Well Name	Work Performed	Amount
LLDSB 1	Install gas lift equipment	$ 42,684
LLDSB 2	Recompletion	$ 212,240
LLDSB 3	Recompletion	$ 89,566
LLDSB 4	Recompletion	$ 74,422
LLDSB 5	Gas lift	$ 10,059
LLDSB 9	New gas line	$ 24,731
LLDSB 14	New gas line	$ 24,731
LLDSB 20	Recompletion	$ 53,841
LLDSB 33	New gas line	$ 26,506
LLDSB 34	Recompletion	$ 81,392
Small amounts on other wells	Gas lift	$ 36,383

Turkey Creek Field – Garfield and Major Counties, Oklahoma

In the nine months ended September 30, 2013, the Company spent $1,808,969 on drilling the Thomas Unit #6H well. The Thomas Unit #6H was not completed due to mechanical issues and has been plugged and abandoned with costs of $2,609,866 charged to dry hole expense during the nine months ended September 30, 2013.

In the nine months ended September 30, 2012, we plugged and abandoned two wells, the Southdown 2D in the Valentine Field and the LLDSB #7 in the Lake Hermitage Field, retiring their costs which comprised asset retirement costs for the Southdown 2D well and asset retirement costs and intangible drilling costs for the LLDSB #7. Costs of the LLDSB #7 well were retired after an unsuccessful attempt to convert it to a salt water disposal well resulted in an oil spill for which we incurred $244,237 of environmental remediation expense in addition to the expense of plugging and abandoning the well. The Company did not incur any environmental remediation expense in the nine months ended September 30, 2013.

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Bear Creek Prospect– Carbon County, Wyoming

Pursuant to a Share Exchange Agreement in 2012, the Company assumed a Purchase and Option Agreement between Armada Oil and Gas and TR Energy, Inc. through which it received leasehold interests in 1,280 acres of land, engineering data, and 2D seismic. During the nine months ended September 30, 2013, the Company determined that this agreement was not in the best interest of the Company, terminated the agreement and surrendered the 1,280 acres of land to TR Energy, Inc.

On November 2, 2012, Armada executed a Seismic and Farm Out Option Contract (the "Anadarko Contract") whereby Anadarko E&P Onshore LLC (successor in interest to Anadarko E&P Company LP), and Anadarko Land Corp. (collectively "Anadarko") agreed to execute a mineral permit granting the Company the nonexclusive right, until May 1, 2013, to conduct 3D survey operations on and across the contracted acreage in Carbon County, Wyoming. If and when the Company drills and completes a test well capable of production and complies with all other terms of the Anadarko Contract, the Company will receive from Anadarko a lease, with an initial term of three (3) years, which provides for the Company to receive a 100 percent (100%) operated working interest in the section upon which the well was drilled. Anadarko will retain a twenty percent (20%) royalty interest in future production. The Company has delivered the seismic data to Anadarko and is evaluating potential drilling sites and funding opportunities for the test well. The Anadarko Contract was amended on October 28, 2013. See Note 11.

Gonzales, Young, and Archer Counties, Texas

Gonzales County. Approximately 300 acres of undeveloped leasehold were acquired in Gonzales County, Texas, in July 2011. The Company has determined that this acreage is a non-core asset and, as such, it allowed the lease to expire in October 2013. The Company assigned no value to this acreage at the time of the Acquisition and recognized no gain or loss upon the expiration of the lease.

Young County. In June 2013, Armada formally took over operatorship of a lease in which it had, in July 2011, acquired a non-operated interest. The leasehold includes approximately 120 acres of land and fourteen stripper wells. At September 30, 2013, the wells were shut in. The Company recognized a $212,160 impairment of the leasehold, leaving a fair value of $150,000. The Company sold its Young County properties in October for $131,250. See Note 11.

Archer County. Approximately 140 acres of land and twelve wells were acquired in September 2011. These properties were considered non-core assets, and, as such, the Company sold them to a third party in June 2013 for $100,932, recognizing no gain or loss on the sale.

Support Facilities and Equipment

The Company's support facilities and equipment serve its oil and gas production activities. The following table details these properties and equipment, together with their estimated useful lives:

	Years	September 30, 2013	December 31, 2012
Tank batteries	7	$ 791,021	$ 798,043
Production equipment	7	1,012,481	1,001,943
Production facilities		55,544	55,544
Field offices (1)	20	150,000	267,089
Crew boats	7	74,793	66,313

Construction in progress (not depreciated)		86,621	19,019
Asset retirement cost	7	256,363	256,363
		2,426,823	2,455,314
Accumulated depreciation		(588,427)	(379,751)
Total support facilities and equipment, net		$ 1,838,396	$ 2,075,563

(1) On July 11, 2013, the Company entered into a real estate contract to sell the Lake Hermitage Camp, with a net book value of $109,467 for $58,000. The sale was consummated on August 8, 2013. After selling expenses of $4,021, the Company incurred a loss of $55,488 on the sale of this property.

In the nine months ended September 30, 2013 and 2012, the Company recognized depreciation expense of $217,508 and $206,290, respectively, on support facilities and equipment.

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Office Furniture, Equipment, and Other

	Years		September 30, 2013		December 31, 2012
Office equipment, computer equipment, purchased software, and leasehold improvements	3	$	210,594	$	203,972
Furniture and fixtures	10		55,569		53,346
			266,163		257,318
Accumulated depreciation			(51,029)		(15,691)
Total property and equipment, net		$	215,134	$	241,627

During the nine months ended September 30, 2013 and 2012, the Company recognized depreciation expense of $35,338 and $8,358, respectively, on office furniture, equipment, and other.

Support facilities and equipment and office furniture, equipment, and other are depreciated using the straight line method over their estimated useful lives.

NOTE 6 – DEBT

Credit Facility and Notes Payable

The Company's notes payable at September 30, 2013 and December 31, 2012 were as follows:

		September 30, 2013		December 31, 2012
Credit Facility	$	8,372,693	$	9,195,963
Private placement of debt, net of discount		511,862		—
Term notes		140,177		90,417
Notes payable outstanding		9,024,732		9,286,380
Less: Current maturities		(9,024,732)		(90,417)
Notes payable – noncurrent	$	—	$	9,195,963

On July 22, 2011, MEI entered into a $25 million senior secured revolving line of credit ("Credit Facility") with F&M Bank and Trust Company ("F&M Bank") that, under its original terms, was to mature on July 22, 2013. The interest rate was the F&M Bank Base Rate plus 1% subject to a floor of 5.75%, payable monthly. During the year ended December 31, 2012, the maturity was extended to July 22, 2014. At September 30, 2013 and December 31, 2012, the interest rate was 5.75%. A 2.00% annual fee is applicable to letters of credit drawn under the Credit Facility.

The Credit Facility provided financing for the 2011 acquisition of TNR, working capital for field enhancements, and general corporate purposes. The Credit Facility was originally subject to an initial borrowing base of $10,500,000 which was fully utilized by the Company with the completion of the acquisition of TNR. The Company obtained letters of credit in the amount of $4,704,037 that were provided to the State of Louisiana to secure asset retirement obligations associated with the properties. $5,693,106 was funded to MEI to complete the transaction, provide working capital for field enhancements and for general corporate purposes. In addition, MEI paid a $102,857 loan origination fee which is being amortized over the life of the loan. The borrowing base is subject to two scheduled redeterminations each year. Loans made under this credit facility are secured by TNR's proved developed producing reserves ("PDP") as well as guarantees provided by the Company, MEI, and the Company's other wholly-owned subsidiaries. Monthly Commitment Reductions were initially set at $150,000 beginning November 22, 2011, and continuing until the first redetermination on or about April 1, 2012. At the first redetermination, the Company was relieved of its obligation to make Monthly Commitment Reductions, and its borrowing base was increased from $10,500,000 to $13,500,000. Future principal reduction requirements, if any, will be determined concurrently with each semi-annual redetermination. In September 2012, F&M performed a second redetermination and increased the Company's borrowing base from $13,500,000 to $14,500,000. In addition, the term of the note was extended from July 22, 2013 to July 22, 2014. In December 2012, the Company drew an additional $4 million from its Credit Facility, resulting in an outstanding principal balance of $9,195,963.

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On May 1, 2013, F&M Bank performed a redetermination of the Credit Facility and reduced the Company's borrowing base from $14,500,000 to $13,375,000 and reinstated its requirement that the Company make monthly principal reduction payments of $75,000 until reset by F&M at the next scheduled redetermination of the Borrowing Base on or around October 1, 2013. As a result of the reduction in the borrowing base, F&M Bank determined the existence of a Borrowing Base deficiency of $450,000. The Company elected, pursuant to terms of its Loan Agreement with F&M Bank to make six equal monthly payments of $75,000, beginning May 22, 2013, to reduce the deficiency to an amount equal to the Borrowing Base. During the nine months ended September 30, 2013, the Company has repaid $823,270 of principal on the Credit Facility.

At inception of the Credit Facility, deferred financing costs of $102,877 were incurred. At September 30, 2013, and December 31, 2012, $16,922 and $78,434, respectively, of amortized deferred financing costs had been recognized as interest expense. At September 30, 2013, $18,802 of deferred financing costs remained to be amortized.

The Credit Facility contains covenants with which the Company must maintain compliance, among which are certain ratios. The Company determined that, at September 30, 2013, it was not in compliance with the interest coverage ratio, required to be greater than or equal to 5.0 but calculated at 4.91. On November 13, 2013, the Company received a default waiver from F&M Bank for the three months ended September 30, 2013, of the Company's noncompliance with the interest coverage ratio. An event of default did not occur as the result of the Company receiving the default waiver, and the Company was in compliance with all of the remaining debt covenants as of September 30, 2013 and December 31, 2012.

The Credit Facility requires that 50% of the projected production from the acquired properties be hedged for 24 months at $100 per barrel or above. The Company entered into various commodity derivative contracts with a single counterparty. For more information see Note 4 – Commodity Derivative Instruments

For the nine months ended September 30, 2013 and 2012, the Company recognized interest expense of $399,258 and $236,915, respectively, on the Credit Facility.

Private Placement of Notes

On March 20, 2013, the Company offered a private placement of debt pursuant to the provisions of Section 4(2), Section 4(6) and/or Regulation D under the Securities Act of 1933, as amended (the "Private Placement"). Pursuant to the Private Placement the Company offered $300,000 minimum and $4 million maximum of Series A Senior Unsecured Notes carrying an interest rate of 9.625% per annum, payable quarterly, with a maturity date of May 30, 2014 (the "Notes"). Under the terms of the offering, Series D Warrants for common shares were issued at closing. The number of warrants issued was calculated by dividing the face value of each subscriber's note by $0.75, and each warrant will be exercisable at $0.75 per share beginning September 1, 2013. At September 30, 2013, the Company had received subscriptions for $655,000 of Notes and issued warrants to purchase 873,333 shares of common stock to subscribers. The Private Placement was closed to additional subscriptions in the second quarter of 2013. The fair value of the warrants, determined as their relative fair value to the notes, calculated using a Black Scholes model, of $248,927 was recorded as discount on the Notes to be amortized to interest expense using an effective interest rate. Assumptions used in determining the fair values of the warrants were as follows:

		2013
Weighted average grant date fair value	$	0.53
Weighted average grant date		March 26, 2013
Discount rate		0.77%
Expected life (in years)		4.9

Weighted average volatility		210.68%
Expected dividends	$	—

Of the Notes, $100,000 was subscribed by James J. Cerna, Jr., who is the President and a director of the Company. $39,199 of debt discount is associated with this note, and warrants exercisable, as described above, for 133,333 shares were issued. $35,000 was subscribed by Marceau Schlumberger, who is a director of the Company. $14,645 of debt discount is associated with this note, and warrants exercisable, as described above, for 46,667 shares were issued.

During the nine months ended September 30, 2013, the Company recognized interest expense of $31,696 on the face value of the notes, and amortization of the debt discount resulted in the recognition of $105,789 as interest expense. Prior to the acquisition of Mesa on March 27, 2013, $198 of interest expense on the notes and $5,190 of debt discount amortization were recognized as interest expense, and were allocated to the purchase price of the Acquisition on March 28, 2013. $143,138 of debt discount remains to be amortized at September 30, 2013.

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Geokinetics Note

As of closing of the Acquisition, Armada had $1,384,139 in an account payable to Geokinetics, Inc. (“Geokinetics”) for seismic work performed by Geokinetics in conjunction with the Anadarko Farmout. On June 7, 2013, the account payable was converted to a note payable secured by the seismic data. The terms of the note provided for payment of the principal balance in three equal monthly installments of $461,380 on June 7, July 8, and August 7, 2013, together with interest at 8% per annum on the unpaid balance. As of September 30, 2013, the Company had fully repaid this note, together with interest of $9,303.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated asset retirement obligations for the nine months ended September 30, 2013.

	2013
Beginning asset retirement obligations	$ 3,507,798
Obligation assumed from acquisition (1)	65,263
Revaluation of Keller Prospect asset retirement obligation	30,794
Accretion expense	170,749
Sale of property	(22,491)
Settlement of asset retirement obligation	(15,678)
Ending asset retirement obligations	$ 3,736,435

(1) ARO of properties acquired in business combination

During the first nine months of 2013, the State of Louisiana refunded the deposit of $23,448 made by the Company on the Valentine Sugars #10 well which was plugged and abandoned before it was acquired from TNR on July 22, 2011. As a result, the asset retirement obligation on the well was eliminated with a recognized gain of $1,328. In addition, the asset retirement obligation for wells in the Keller Prospect in Young County, Texas, was revalued and increased by $30,794. The asset retirement obligation for the wells in Parish and Tribune Prospects in Archer County, Texas, was retired upon sale with no gain or loss.

In the nine months ended September 30, 2013 and 2012, the Company recognized $170,749 and $112,311, respectively, of accretion expense on its asset retirement obligations.

NOTE 8 – INCOME TAXES

We recognize the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. We have not taken a tax position that, if challenged, would have a material effect on the consolidated financial statements or the effective tax rate for the nine months ended September 30, 2013.

As of September 30, 2013, the Company has U.S. net operating loss carry forwards of approximately $7.5 million which begin to expire in 2028.

NOTE 9 – COMMON STOCK

The Company is authorized to issue 100 million shares of common stock with a $0.001 par value per share. At September 30, 2013 and December 31, 2012, the Company had 56,030,473 and 33,732,191 shares issued and outstanding, respectively. The increase of 22,298,282 common shares outstanding is the result of the issuance of 21,475,284 shares valued at $11,927,048 based on the date of grant, in the business combination consummated at March 28, 2013, the vesting of 108,000 shares valued at $54,640, based on the date of grant, of restricted stock to employees, the issuance of 75,000 shares valued at $19,875 to a consultant, and the issuance of an additional 639,998 shares to the holders of Series D warrants pursuant to an Offering Modification Agreement ("Offering Modification") between the Company and eight investors which occurred on April 23, 2013. The shares issued pursuant to this modification were valued together with an equal amount of warrants issued as part of the transaction in relation to the consideration paid by investors for the shares and the warrants. See Warrants in NOTE 10 below for more information on the fair value of the shares and the warrants issued pursuant to this modification.

All share and per share amounts have been retroactively adjusted to reflect the ratio of the Company's common stock to holders of shares in Mesa Energy Holdings, Inc., prior to the acquisition.

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NOTE 10 – SHARE - BASED COMPENSATION

Warrants

Pursuant to the Offering Modification, eight investors who in October and November 2012 contributed $720,000 in the aggregate to participate in an offering of securities comprising 800,002 shares of common stock and warrants to purchase an equal number of shares of common stock at $1.25 per share were granted an additional 639,998 shares and warrants to purchase an equal number of shares of common stock at $0.75 per share. In addition, the exercise price of $1.25 per share of the initially granted warrants was reduced to $0.75 per share. As a result of the Offering Modification the fair value of the common shares was reduced by $112,063 from $477,192 to $365,039. The fair value of the warrants was increased by $177,902 from $177,059 to $354,961. The changes in fair value were recognized in Additional Paid-In Capital, with a loss on the modification of $65,749 recognized in Other Income.

Under a private placement commenced on March 20, 2013, Series D Warrants to purchase 840,000 common shares were issued at periodic closings with the final occurring on April 30, 2013. Each warrant will be exercisable at $0.75 per share beginning September 1, 2013. The fair value of the warrants, determined as their relative fair value to the notes, calculated using a Black Scholes model, was $241,083. Assumptions used in determining the fair values of the warrants were as follows:

		2013
Weighted average grant date fair value	$	0.54
Weighted average grant date		March 24, 2013
Discount rate		0.77%
Expected life (in years)		4.9
Weighted average volatility		205.74%
Expected dividends	$	—

The following table summarizes the Company’s warrant activities for the nine months ended September 30, 2013:

	Shares		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2012	200,000	$	2.50	3.7 years	$	—
Granted under Armada acquisition	7,414,787		2.07	3.8 years		—
Modified	639,998		0.75	4.4 years		—
Granted	473,333		0.75	4.4years		—
Exercised	—		—			
Cancelled/Expired	—		—			
Outstanding at September 30, 2013	8,728,118	$	2.01	3.9 years	$	—
Exercisable at September 30, 2013	8,728,118	$	2.01	3.9 years	$	—

Stock Options

Options to purchase 280,000 shares of common stock were granted in 2013 prior to the date of the Acquisition, the estimated fair value of which was $163,021. Options to purchase an additional 1,322,000 shares, of which 1,270,000 were granted to directors and 52,000 to employees, were granted after the date of the Acquisition through September 30, 2013. The estimated fair values of those grants were $507,406 and $16,492, respectively. The following summarizes the values from and assumptions for the Black-Scholes option pricing model for stock options issued during the nine months ended September 30, 2013:

	2013
Weighted average grant date fair value	$ 0.39
Weighted average grant date	April 14, 2013
Weighted average risk-free interest rate	0.74%
Expected life (in years)	4.5
Weighted average volatility	201.81%
Expected dividends	$ —

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The following table summarizes the Company’s stock option activities for the nine months ended September 30, 2013:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2012	2,202,800	$ 0.76	4.5 years	$ —
Granted (1)	1,602,000	0.39	4.4 years	—
Exercised	—	—		
Cancelled/Expired	(998,800)	—		
Outstanding at September 30, 2013	2,806,000	$ 0.49	4.0 years	$ —
Exercisable at September 30, 2013	2,458,600	$ 0.48	3.9 years	$ —

(1) Comprises 240,000 shares of restricted stock grant converted to options on March 20, 2013, 1,270,000 granted to directors, and 92,000 granted to employees.

Compensation expense related to stock options of $581,164 and $116,018 was recognized for the nine months ended September 30, 2013 and 2012, respectively. At September 30, 2013, the Company had $79,746 of unrecognized compensation expense related to outstanding unvested stock options, which will be fully recognized over the next 5 years. No stock options have been exercised during the nine months ended September 30, 2013.

Restricted Stock

The following table summarizes the Company’s restricted stock activities for the nine months ended September 30, 2013:

	Shares
Unvested Restricted Shares at December 31, 2012	348,000
Granted	455,651
Granted under offering modification	639,998
Vested and issued	(1,203,649)
Cancelled/Expired (1)	(240,000)
Unvested Restricted Shares at September 30, 2013 (2)	—

(1) Includes 240,000 shares of restricted stock grant converted to options on March 20, 2013

(2) Upon closing of the Acquisition, unvested grants of restricted shares were multiplied by 0.4 pursuant to the terms of the Acquisition. Because the fair value of the unvested shares had been previously determined using the closing trading price on the date of grant of $0.15, while the closing trading price on the date of acquisition was $0.55 per share, incremental expense of $11,340 was added to the unamortized stock compensation expense during the nine months ended September 30 2013.

At September 30, 2013, the Company had no unrecognized compensation expense related to unvested restricted stock grants.

NOTE 11 – SUBSEQUENT EVENTS

F&M Bank Credit Facility

Effective October 1, 2013, F&M Bank and the Company entered into the Second Amendment to the Loan Agreement dated July 22, 2011 as previously amended on September 21, 2012 (the "Amendment"). The Amendment provides for the reduction of the Borrowing base by $675,000 to $12,700,000 from $13,375,000; resets monthly repayments of principal to $50,000 per month until the next scheduled redetermination to occur on or about April 1, 2014, and requires that general and administrative expense not exceed 27% of revenue for any two consecutive quarters.

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Sale of Young County Properties

Effective October 1, 2013, the Company sold its Young County, Texas, properties for $131,250, recognizing a loss of $18,750 on the sale. The Company exchanged the property for a temporary override in the production of the properties until the sale price has been received in full. As a result of the sale, the Company is eliminating the associated asset retirement obligation of $77,489 and recognizing a gain of $2,100.

Expiration of Gonzales County, Texas, Lease

On October 25, 2013, the Company allowed the lease covering approximately 300 acres of undeveloped leasehold, obtained through the Acquisition, to expire. The Company had assigned no value to this acreage at the time of the Acquisition and recognized no gain or loss upon the expiration of the lease.

Amendment of Anadarko Contract

On October 28, 2013, the Company and Anadarko entered into a Third Amendment to the Seismic and Farmout Option Contract dated October 22, 2012 which included the following changes to the original agreement, as amended:

The Company is now:

- obligated to commence drilling of the Initial Test Well on or before July 31, 2014 (previously December 31, 2013);
- granted an option for a period of 180 days from date Initial Contract Depth is reached in the Initial Test Well to commence drilling of a Continuous Option Test well, regardless of well type; and
    - allowed to reduce control of well insurance coverage from $25,000,000 to $10,000,000

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

This report contains forward-looking statements. All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q, including without limitation, statements in this Management's Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated working capital, business strategy, the plans and objectives of our management for future operations and those statements preceded by, followed by or that otherwise include the words "believe," "expects," "anticipates," "intends," "estimates," "projects," "target "plans," "objective," "should" or similar expressions or variations on such expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, our inability to obtain adequate financing, insufficient cash flows and resulting illiquidity, our inability to expand our business, government regulations, lack of diversification, volatility in the price of oil and/or natural gas, increased competition, results of arbitration and litigation, stock volatility and illiquidity, our failure to implement our business plans or strategies and general economic conditions. A description of some of the risks and uncertainties that could cause our actual results to differ materially from those described by the forward-looking statements in this Quarterly Report on Form 10-Q appears in the section captioned "Risk Factors" in our 2012 Annual Report on Form 10-K.

Except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based.

History

Armada Oil, Inc. (the "Company", "Armada", or "we") was incorporated under the laws of the State of Nevada on November 6, 1998, under the name "e.Deal.net, Inc." On June 20, 2005, the Company amended its Articles of Incorporation to effect a change of name to International Energy, Inc. On June 27, 2011, the Company amended its Articles of Incorporation to change its name to NDB Energy, Inc. On May 7, 2012, the Company filed a Certificate of Amendment to its Articles of Incorporation to change its name to Armada Oil, Inc.

On March 28, 2013 Armada formed a business combination with Mesa Energy Holdings, Inc. ("Mesa"), pursuant to which Armada acquired from Mesa substantially all of the assets of Mesa consisting of all of the issued and outstanding shares of Mesa Energy, Inc. ("MEI"), whose predecessor entity, Mesa Energy, LLC, was formed in April 2003 as an exploration and production company in the oil and gas industry. Although Armada was the legal acquirer, Mesa was the accounting acquirer.

Armada has a farmout agreement with Anadarko Petroleum on approximately 8,750 net mineral acres in Carbon County, Wyoming ("Project Acreage"). The Project Acreage is generally 40 miles west of Laramie, Wyoming and lies in the emerging fairway of the Niobrara Shale play which is currently very active in northern Colorado and eastern Wyoming.

MEI's oil and gas operations are conducted through itself and its wholly owned subsidiaries. MEI acquired Tchefuncte Natural Resources, LLC ("TNR") in July 2011. TNR owns interests in 80 wells and related surface production equipment in five fields located in Plaquemines and Lafourche Parishes, Louisiana. Mesa Gulf Coast, LLC ("MGC") became the operator of all operated properties in Louisiana in October 2011. Mesa Midcontinent, LLC is a qualified operator in the state of Oklahoma and operates our properties in Garfield and Major Counties, Oklahoma. MEI is a qualified operator in the State of New York and operates the Java Field.

The Company’s operating entities have historically employed, and will continue in the future to employ, on an as-needed basis, the services of drilling contractors, other drilling related vendors, field service companies and professional petroleum engineers, geologists and land men as required in connection with future drilling and production operations.

Overview

We are an oil and gas exploration and production (“E & P”) company engaged primarily in the acquisition, drilling, development, production and rehabilitation of oil and gas properties.

Our business plan is to build a strong, balanced and diversified portfolio of oil and gas reserves and production revenue through the acquisition of properties with solid, long-term existing production with enhancement potential and the development of highly diversified, multi-well developmental drilling opportunities.

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We continuously evaluate opportunities in the United States' most productive basins, and we currently have interests in the following:

- Lake Hermitage Field, a producing oil and natural gas field in Plaquemines Parish, Louisiana;
- Valentine Field, a producing oil and natural gas field in Lafourche Parish, Louisiana;
- Larose Field, a producing oil and natural gas field in Lafourche Parish, Louisiana;
- Bay Batiste Field, a producing natural gas field in Plaquemines Parish, Louisiana;
- Manila Village Field, a currently shut-in field in Plaquemines Parish, Louisiana;
- Turkey Creek Field, an area of interest in which we hold undeveloped leasehold interests and a farm-out in Garfield and Major Counties, Oklahoma;
- Carbon County, Wyoming, an area of interest in which we hold a farm-out agreement with Anadarko Petroleum Company; and
- Java Field, a natural gas development project in Wyoming County in western New York.

In the nine months ended September 30, 2013, we spent $261,863 in geological, geophysical, and engineering expense in performing the scientific work requisite to developmental and exploratory work in Louisiana, Wyoming, and Oklahoma to further our business plan.

The following discussion highlights the principal factors that have affected our financial condition as well as our liquidity and capital resources for the periods described and provides information which management believes is relevant for an assessment and understanding of the statements of financial position, results of operations and cash flows presented herein. This discussion should be read in conjunction with our unaudited financial statements, related notes and the other financial information included elsewhere in this report.

Louisiana Operating Area

On July 22, 2011, the Company's wholly owned subsidiary, Mesa Energy, Inc. ("MEI"), completed the acquisition of Tchefuncte Natural Resources, LLC ("TNR"), a Louisiana operator. Immediately prior to MEI's closing of the TNR acquisition, TNR completed the acquisition of properties in five fields in South Louisiana from Samson Contour Energy E & P, LLC. TNR, now a wholly owned subsidiary of MEI, owns 100% working interests in the Lake Hermitage Field in Plaquemines Parish, Louisiana along with various working interests in producing properties in four additional fields in Plaquemines and Lafourche Parishes, Louisiana.

We believe that, as a result of our ongoing program of workovers, recompletions, sidetracking or otherwise returning shut-in wells to production, improving operational efficiencies and continued optimization of the gas lift systems, significant increases in production can continue to be achieved in these fields. We expect to continue our workover and recompletion program and to accomplish a number of additional enhancements and upgrades to facilities and flow lines in the fourth quarter of 2013, all of which will be funded out of cash flow or financing we are seeking to facilitate acceleration of these programs. These efforts should significantly increase production and PDP reserves. Extensive geological and engineering evaluations of the Lake Hermitage and Valentine Fields have revealed multiple opportunities and we are prioritizing and planning for those opportunities on an ongoing basis. In addition, our technical team is in the process of refining a number of additional drilling locations and we expect to sidetrack existing wells into deeper zones and drill the first of several developmental wells in 2014. We are reviewing a number of deep targets with potential for farm out or joint venture with other operators and are actively pursuing additional acquisition opportunities in South Louisiana.

The Louisiana Operating Area is located in Lafourche and Plaquemines Parishes in Louisiana and includes:

Producing Fields - Plaquemines and Lafourche Parishes, Louisiana

Lake Hermitage Field – Plaquemines Parish, Louisiana

The Lake Hermitage Field is located in Plaquemines Parish, Louisiana, approximately 25 miles south-southeast of New Orleans, Louisiana. The field is a salt dome structure discovered in 1928 and has produced significant quantities of oil and gas from multiple sandstone reservoirs between 3,100 and 14,200 feet deep. It is situated in a shallow, marshy environment on the west side of the Mississippi River.

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The Company owns a 100% working interest and 75% net revenue interest in each of the eighteen wells in the Lake Hermitage Field. A total of 3,589 mineral acres is held by production in the field. Ten wells are currently shut-in pending evaluation for workover and/or future recompletion in uphole zones or sidetrack into deeper zones, and an additional well is being evaluated for conversion to a salt water disposal well which would reduce expenses and allow for increased daily handling of fluid. There are three processing facilities and tank batteries in the field. The high gravity crude oil produced at Lake Hermitage is transported out of the field by barge. In the first quarter of 2013, we successfully replaced the tubing string in the LLDSB #10 well which resulted in a return to stable daily production of over 100 barrels per day. In addition, the LLDSB #3 was successfully recompleted into the UL-4 sand which resulted in a similar increase in production. On May 1, 2013, we initiated a new round of workovers and recompletions in the field and those efforts also had a positive impact on production.

Valentine Field – Lafourche Parish, Louisiana

The Valentine Field is located in the Mississippi Delta area in Lafourche Parish, Louisiana, approximately 35 miles southwest of New Orleans, Louisiana. This gas and oil field was discovered in 1933 on the east flank of the Valentine Salt Dome as a result of torsion-balance and reflection-seismic surveying.

The company owns approximately 3,082 net mineral acres that are held by production in the field and holds operated working interests averaging in excess of 94% with net revenue interests averaging approximately 80%.

Twenty-five of the forty wells operated by MGC are currently shut-in pending evaluation for future workover or recompletion to uphole zones. There are three salt water disposal wells in the field. An extensive geological and engineering evaluation review of the Valentine Field is ongoing and we have identified a number of recompletion opportunities as well as a couple of potential drilling locations.

The processing facilities and tank batteries are strategically located throughout the field and have plenty of excess capacity. A field operations center is centrally located in the field. Access to pipelines and crude oil markets is excellent.

Larose Field – Lafourche Parish, Louisiana

The Larose Field, discovered in 1953 is located in Lafourche Parish, Louisiana, and is approximately 25 miles southwest of New Orleans, Louisiana. The field is on a southwesterly plunging anticlinal ridge that trends in a NE-SW direction and is approximately five miles along the NE-SW axis and is two and one-half miles wide. There are three major faults, striking east to west and dipping to the south that cross the ridge and separate the field into three main producing segments.

The company operates one well in Larose field in which it owns a 100% working interests and a 72.25% net revenue interest and owns various non-operated working interests that range from 10.4% to 57.6% and net revenue interests from 8.7% to 41.2% covering approximately 350 net mineral acres. The processing facilities and tank batteries are well located and have plenty of excess capacity, and the access to pipelines and crude oil markets is excellent.

MGC has a production handling agreement (“PHA”) in place with an outside operator which takes advantage of the excess capacity and generates additional revenue. Also, the PHA provides the additional advantage of access to artificial lift gas on an as needed basis.

Bay Batiste Field - Plaquemines Parish, Louisiana

The Bay Batiste Field, discovered in 1983, is located in Plaquemines Parish, Louisiana approximately 35 miles east-southeast of New Orleans, Louisiana. It is situated in a shallow water environment on the west side of the Mississippi River.

The Company owns and operates an average 59.43% working interest and 41.89% net revenue interest in seven wells in the Bay Batiste Field. One well is currently producing and the other four wells are currently shut-in pending evaluation for future workover or recompletion in uphole zones. Approximately 74 net mineral acres are held by production by the producing well. The salt water disposal well and two production facilities have plenty of excess capacity to handle production from recompleted wells or from third party operators nearby. Access to markets is excellent.

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SE Manila Village Field – Plaquemines Parish, Louisiana

The SE Manila Village Field is located in Plaquemines Parish, Louisiana approximately 45 miles southeast of New Orleans, Louisiana. The field was discovered in 1985 and is situated in a shallow open-water environment on the west side of the Mississippi River.

The Company owns a non-operated 21.09% working interest and 14.48% net revenue interest in two outside operated wells in the Manila Village Field. 16.88 net mineral acres are held by production in the field. The wells are scheduled to be plugged and abandoned.

Oklahoma Operating Area

During 2012, the Company began a leasing and acreage acquisition program in Major and Garfield Counties, Oklahoma, and acquired, through a combination of grass roots leasing and farmouts, approximately 3,200 net mineral acres. We are continuing to actively pursue agreements with operators to acquire additional acreage that is held by production. We refer to our acreage position in Major and Garfield Counties, OK, as the Turkey Creek Field.

The Mississippian Limestone in this area of Oklahoma is a proven zone that has been drilled vertically for many years so there is a lot of well control available with no need for seismic. The Woodford Shale is immediately below the Mississippian and is about 80 feet thick. Early reports indicate that the Woodford is oil bearing and quite productive in the area of interest. Potential reserves in the Mississippian on a per well basis have been reported to be 200,000 to 400,000 barrels per well. The Woodford could increase the potential reserves recoverable by a similar amount. A multi-stage frac is required using acid, fresh water and a simple sand proppant. The Mississippian produces some water, so disposal wells will likely be required. The oil is light, sweet crude with a gravity of 40 to 45 dg. We believe this is an opportunity to establish a repeatable drilling program in an area with a high drilling success rate.

In December of 2012, the Company commenced the drilling of its first horizontal well in the play. A pilot hole was drilled to a depth of 7,946 feet. A sophisticated set of logs was run in the pilot hole along with pressure testing and the retrieval of cores for evaluation. That set of information revealed not only solid potential and a good porosity streak in the Mississippian Limestone, but also excellent potential in the Woodford Shale. Unfortunately, the well-bore was ultimately lost due to the back to back mechanical failure of two horizontal drilling motors and the resulting negative affect on the tangent of the curve. These incidents combined with a difficult shale section just above the Mississippian Limestone precipitated a series of issues that ultimately could not be overcome. As a result, we had to plug and abandon the well-bore. Accordingly, we view the exercise as a geological success and a mechanical failure and expect to move over and redrill the well from the same surface location when resources allow.

Since that time, other operators have drilled additional wells in the area, both in the Mississippian and in the Woodford, in many cases drilling multiple wells in both formations from the same drilling pad. The Company believes the Woodford has as much oil production potential in the area as the Mississippian, and the Woodford is rapidly becoming an exciting and emerging play in its own right.

Wyoming Operating Area

The Company holds a farmout agreement with Anadarko (Anadarko Contract) on approximately 8,750 net mineral acres in Carbon County, Wyoming ("Project Acreage"). The Project Acreage is generally 40 miles west of Laramie, Wyoming and lies in the emerging fairway of the Niobrara Shale play which is currently very active in northern Colorado and eastern Wyoming. In addition, there are a number of conventional zones, both above and below the Niobrara, which are highly productive in the area. A 3-D seismic shoot over the acreage position by the Company has been processed and evaluated, and the results have not only confirmed potential in a number of the deep conventional zones but also solid potential in the Niobrara. The Company expects to drill its first well in the Project Acreage in 2014. The Company has well logs from nearby wells showing the presence of all three Niobrara "benches", and well control and core data indicates that the Niobrara in this area meets or exceeds the positive attributes of the DJ Basin and Wattenberg Fields in northern Colorado, both of which are being actively drilled by Anadarko, Noble and other major independents.

Initial indications from those fields indicate drilling and completion costs for the Niobrara of under $5,000,000, potential reserves per well of 300,000 to 600,000 barrels and liquids ratios of 60% to 80%.

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On the conventional side, three nearby fields in conventional zones have produced in excess of 65 million barrels of oil and 23 BCF of gas. A number of potential conventional drilling locations were identified/confirmed as a result of the recently completed 3-D seismic shoot.

Based on a recent article in the Oil & Gas Investor, companies drilling the Niobrara in the DJ Basin to the south are horizontally drilling all three Niobrara benches separately plus the deeper Codell formation, resulting in as many as 16 horizontal wells per section. That drilling plan could theoretically result in over 200 wells on the existing Anadarko farmout acreage. Anadarko owns the minerals underlying the contracted acreage as well as a substantial amount of additional acreage in the area.

Under the recently amended Anadarko Contract, the Company is obligated to commence drilling of the initial test well on or before July 31, 2014. If the Company fails to drill said well in a timely manner, the Company shall be deemed to have relinquished its right to acquire any interest in Anadarko's acreage under the Anadarko Contract. If the Company drills an initial test well capable of production in paying quantities to the initial contract depth (approximately 9,500 feet), completes it as a producer and otherwise complies with and performs all other terms, covenants, and conditions of the Anadarko Contract, the Company will earn and be entitled to receive from Anadarko a lease, effective 30 days from the date of the release of the rig from the test well location, covering all of Anadarko's oil and gas estate in the respective drill site section limited to the earned depth. The lease to be so earned by Armada will (i) be for a primary term of three (3) years; and (ii) provide for a lessor's royalty of twenty percent (20%), proportionately reduced as appropriate and subject to any gas sales, purchase, transportation or gathering contracts affecting the leased lands on the date of the Anadarko Contract. The Company will then have the right to continue to drill additional wells on the contracted acreage, subject to a drilling schedule, and earn additional drill site sections as described above. The contracted acreage covers approximately 8,750 net mineral acres.

A location for the Initial Test Well has been tentatively selected and additional locations for future wells are being evaluated. The Company intends to take an aggressive approach to exploiting the Anadarko acreage position.. The implementation of an aggressive drilling schedule using leading-edge shale drilling and completion technology should enable the Company to rapidly identify and develop significant oil and gas reserves in the Niobrara Shale.

New York Operating Area

The New York Operating Area is located in Wyoming County in western New York.

Java Field – Wyoming County, New York

In 2009, Mesa Energy, Inc. acquired the Java Field, which was discovered in 1978. The Medina Sandstone is the productive natural gas interval for the 19 producing natural gas wells in the field. The total depth range of these vertical wells is approximately 2,850' – 3,500'. A development project targeting the Marcellus Shale, as is present in a large area of the Appalachian Basin in the northeastern United States, is the primary goal.

The acquisition included 19 producing natural gas wells, their associated leases, units and all equipment; two surface tracts of land totaling approximately 36 acres; and two pipeline systems; a 12.4 mile pipeline and gathering system that serves the existing field, as well as a separate 2.5 mile system located northeast of the field. The company owns approximately 78% net revenue interest in leases covering 2,851.50 gross and net acres, more or less.

Production is nominal from the wells but serves to hold the acreage for future development. In early 2010, we recompleted and fracked the Reisdorf Unit #1 and the Ludwig #1 in the Marcellus Shale. The initial round of testing and analysis provided a solid foundation of data that strongly supports further development of the Marcellus Shale in western New York. Formation pressures and flow-back rates were much higher than expected providing a clear indication of the potential of the resource.

We believe that horizontal drilling, successfully done at this depth in other basins, is ultimately what is needed to maximize the resource.

The State of New York placed a moratorium on horizontal drilling and high volume fracture stimulation in late 2008 in order to develop new permitting rules. Environmental activism has resulted in continued delays of this process and there can be no assurance when such permitting rules will be issued or what restrictions such permits might impose on producers. Accordingly, we have been unable to continue with our development plans in New York for the time being. Unless the moratorium is removed and new permitting rules provide for the economic development of these properties, production on these properties will remain marginally economic.

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Texas Operating Area

In June of 2013, Armada formally took over operatorship of a lease in which it previously held as a nonoperated working interest in Young County, Texas totaling approximately 120 acres of land and fourteen stripper wells. Armada determined this property to be a non-core asset and sold it effective October 1, 2013, for $131,250. Armada will receive a temporary overriding royalty interest in the production of this property until the sale price has been received in full.

Adjusted EBITDA as a Non-GAAP Performance Measure

In evaluating our business, management believes earnings before interest, taxes, depreciation, depletion, amortization and accretion, unrealized gains and losses on financial instruments, gains and losses on sales of assets and stock-based compensation expense ("Adjusted EBITDA") is a key indicator of financial operating performance and is a measure of our ability to generate cash for operational activities and future capital expenditures. Adjusted EBITDA is not a GAAP measure of performance. We use this non-GAAP measure primarily to compare our performance with other companies in our industry and as a measure of our current liquidity. We believe that this measure may also be useful to investors for the same purposes and as an indication of our ability to generate cash flow at a level that can sustain or support our operations and capital investment program. Investors should not consider this measure in isolation or as a substitute for income from operations, or cash flow from operations determined under GAAP, or any other measure for determining operating performance that is calculated in accordance with GAAP. In addition, because Adjusted EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures that may be disclosed by other companies.

The following is a reconciliation of our net income in accordance with GAAP to our Adjusted EBITDA for the nine-month periods ending September 30, 2013 and 2012:

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Net income (loss)	$ (197,212)	$ (356,875)	$ (1,743,298)	$ 164,687
Adjustments:				
Interest (income) expense, net	252,425	141,949	645,187	410,289
Depreciation, depletion, accretion and impairment	522,933	361,484	1,554,062	1,215,448
Dry hole expense	—	—	2,609,866	—
(Gain) loss on sale of oil and gas properties	55,448	—	55,448	—
(Gain) loss on settlement of asset retirement obligation	—	—	(1,328)	—
Bargain purchase gain	—	—	(1,455,879)	—
Unrealized (gain) loss on change in commodity derivative instruments	507,389	862,306	455,561	938,606
Loss on modification of offering terms	—	—	65,749	—
(Gain) loss on change in convertible debt derivative	—	17,714	—	536,422
Share-based compensation	41,782	76,054	637,614	273,478
Income tax (benefit) expense	(349,663)	(195,850)	(1,637,592)	272,164
Adjusted EBITDA	$ 833,102	$ 906,782	$ 1,185,390	$ 3,811,094

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Results of Operations

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Revenue

The following table summarizes our revenues from commodity sales during the three months ended September 30, 2012 and 2012.

	Three Months Ended September 30, 2013	2012	Difference	Percentage Change
Revenues				
Oil	$2,771,466	$2,744,219	$27,247	1.0 %
Natural gas	440,996	474,725	(33,729)	-7.1 %
Natural gas liquids	53,552	8,527	45,025	528.0 %
Total	$3,266,014	$3,227,471	$38,543	-14.9 %
Sales volumes				
Oil (Bbls)	24,924	26,303	(1,379)	-5.2 %
Natural gas (MCF)	114,515	154,377	(39,862)	-25.8 %
Natural gas liquids (Bbl)	1,295	353	942	266.8 %
Total BOE	45,305	52,385	(40,299)	-76.9 %
Total BOE/day	492	569		
Average prices				
Oil (per Bbl)	$111.20	$104.33	$6.87	6.6 %
Natural gas (per MCF)	3.85	3.08	0.78	25.2 %
Natural gas liquids (per Bbl)	41.36	24.16	17.20	71.2 %
Total per BOE	$72.09	$61.61	$24.85	40.3 %

Revenues from commodity sales increased during the three months ended September 30, 2013 over the three months ended September 30, 2012 because (i) we had several wells in Lake Hermitage shut-in during and following Hurricane Isaac in 2012 and (ii) because of increased 2013 production due to workovers and recompletions of several Lake Hermitage wells. In addition, average commodity prices increased during the three months ended September 30, 2013 over the three months ended September 30, 2012.

In addition to revenues from commodity sales, during the three months ended September 30, 2013, we had $36,107 of revenue from lease fuel; marketing, compression, and transportation fees; and production handling fees for a third party. During the three months ended September 30, 2012, we had $92,306 of such income. The decrease over 2012 is attributable to lower sales volumes with which some of the fees are associated.

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Operating expenses

Operating expenses for the three months ended September 30, 2013 and 2012 are set forth in the table below:

	Three Months Ended September 30, 2013	2012	Difference	Percentage Change
Costs and Expenses				
Lease operating expense (1)	$1,261,571	$1,126,657	$134,914	12.0 %
Production and ad valorem taxes	359,660	422,194	(62,534)	-14.8 %
Exploration expense (2)	179,517	137,090	42,427	30.9 %
Depletion, depreciation, amortization, and impairment expense (3)	522,933	361,484	161,449	44.7 %
Loss on sale of oil and gas properties (4)	55,448	—	55,448	N/A
General and administrative expense	798,862	834,953	(36,091)	-4.3 %
Total operating expenses	$3,177,991	$2,882,378	$295,613	10.3 %

(1) Increased workover expense net of a $112,493 decrease in lease operating expenses for nonoperated properties

(2) Exploration expense increased due to use of geological consultants to evaluate the Wyoming seismic, Oklahoma drilling potential, and potential for enhancing the Louisiana reserves base

(3) Primarily attributable to impairment of Young County, Texas, property at September 30, 2013

(4) Sale of Lake Hermitage Camp for less than net book value.

Operating expenses expressed in barrel of oil equivalent (“BOE”) for the three months ended September 30, 2013 and 2012 are set forth in the table below:

	Three Months Ended September 30, 2013	2012	Difference	Percentage Change
Costs and Expenses				
Lease operating expense	$27.85	$21.51	$6.34	29.5 %
Production and ad valorem taxes	7.94	8.06	(0.12)	-1.5 %
Exploration expense	3.96	2.62	1.35	51.4 %
Depletion, depreciation, amortization, and impairment expense	11.54	6.90	4.64	67.3 %
Loss on sale of oil and gas properties	1.22	—	1.22	N/A
General and administrative expense	17.63	15.94	1.69	10.6 %
Total operating expenses	$70.14	$55.03	$15.12	27.5 %

Operating income. As a result of the above described revenues and expenses, we recognized operating income of $124,130 in the three months ended September 30, 2013 as compared to operating income of $352,988 in the three months ended September 30, 2012.

Interest expense. Interest expense increased to $252,425 for the three months ended September 30, 2013, from $143,940 for the three months ended September 30, 2012. The increase was primarily attributable to amortization of discount on notes payable associated with a private placement of securities, as well as payment of interest on the notes themselves, and interest expense on premium financed insurance notes. In addition, the cash balance on our credit facility of $8,372,693 is higher at September 30, 2013 than the balance of $5,195,963 at September 30, 2012.

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Unrealized gain on changes in derivative value. The unrealized loss on change in derivatives – commodity contracts for the three months ended September 30, 2013 and 2012 was $507,389 and $862,306, respectively. These unrealized losses were the result of the change in value of the net derivative assets and liabilities from that of the prior reporting period. The values underlying the derivatives are estimates of predicted future commodity prices based on current market activity and projections of future market activity. Additional contributors to fluctuations in the fair value of the derivative are additions to and unwindings of hedged positions during any reporting period.

Realized gain on changes in derivatives – commodity contracts. Cash settlements from hedging our sales of oil and gas production were $101,409 in the three months ended September 30, 2013 as compared to $117,741 in the three months ended September 30, 2012. The decrease of $16,332 is attributable to the same factors that affect the unrealized gains or losses associated with our commodity derivative contracts.

Income tax benefit (expense). State and federal income tax benefit for the three months ended September 30, 2013 and 2012 were $349,663 and $195,850, respectively. The increase in the income tax benefit in the three months ended September 30, 2013 is attributable primarily to higher lease operating expense and exploration expense, lower realized gain on commodity contracts, and higher interest expense in the three months ended September 13, 2013 as compared to September 13, 2012.

Net income (loss). Due to the reasons set forth above, our net loss for the three months ended September 30, 2013 was $198,212 ($0.00 per basic and diluted common share). Our net loss for the three months ended September 30, 2012 was $356,875 ($0.00 per basic and diluted common share).

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Revenue

The following table summarizes our revenues from commodity sales during the nine months ended September 30, 2012 and 2012.

	Nine Months Ended September 30, 2013	2012	Difference	Percentage Change
Revenues				
Oil	$8,157,679	$9,807,859	$(1,650,180)	-16.8 %
Natural gas	1,453,838	1,576,485	(122,647)	-7.8 %
Natural gas liquids	155,779	88,170	67,609	76.7 %
Total	$9,767,296	$11,472,514	$(1,705,218)	-14.9 %
Sales volumes				
Oil (Bbls)	74,436	89,577	(15,141)	-16.9 %
Natural gas (MCF)	466,776	579,857	(113,081)	-19.5 %
Natural gas liquids (Bbl)	3,779	1,983	1,796	90.6 %
Total BOE	156,011	188,210	(126,466)	-67.2 %
Total BOE/day	571	687		
Average prices				
Oil (per Bbl)	$109.59	$109.49	$0.10	0.1 %
Natural gas (per MCF)	3.11	2.72	0.40	14.6 %

Natural gas liquids (per Bbl)	41.22	44.46	(3.24	)	-3.24	%
Total per BOE	$62.61	$60.96	$(2.74	)	-2.74	%

Revenues from commodity sales decreased during the nine months ended September 30, 2013 over the nine months ended September 30, 2012 due to natural decline in well production as well as some wells being offline in the first and second quarters of 2013 for workovers and recompletions.

In addition to revenues from commodity sales, during the nine months ended September 30, 2013, we had $78,771 of revenue from lease fuel; marketing, compression, and transportation fees; and production handling fees for a third party. During the nine months ended September 30, 2012, we had $247,358 of such income. The decrease over 2012 is attributable to lower sales volumes with which some of the fees are associated.

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Operating expenses

Operating expenses for the nine months ended September 30, 2013 and 2012 are set forth in the table below:

	Nine Months Ended September 30, 2013	2012	Difference	Percentage Change
Costs and Expenses				
Lease operating expense (1)	$4,748,588	$3,690,034	$1,058,554	28.7 %
Production and ad valorem taxes (2)	1,140,253	1,481,785	(341,532)	-23.0 %
Environmental remediation expense	—	244,237	(244,237)	-100.0 %
Exploration expense (3)	271,863	233,089	38,774	16.6 %
Dry hole expense (4)	2,609,866	—	2,609,866	N/A
Depletion, depreciation, amortization, and impairment expense (5)	1,554,062	1,215,448	338,614	27.9 %
Loss on sale of oil and gas properties (6)	55,448	—	55,448	N/A
(Gain) loss on settlement of asset retirement obligation (7)	(1,328)	116,394	(117,722)	-101.1 %
General and administrative expense (8)	3,401,724	2,542,226	859,458	33.8 %
Total operating expenses	$13,780,476	$9,523,213	$4,257,223	44.7 %

(1) Increased workover expense net of third quarter reduced lease operating expenses for nonoperated properties
(2) Decreased sales volumes
(3) Increased use of geological consultants to evaluate the Wyoming seismic, Oklahoma drilling potential, and potential for enhancing the Louisiana reserves base net of 2012's Oklahoma leasing campaign
(4) Mechanical failure in the drilling of the Thomas #6H well in Oklahoma
(5) Primarily attributable to impairment of Young County, Texas, property at September 30, 2013.
(6) Sale of Lake Hermitage Camp for less than net book value.
(7) A 2013 gain of $1,328 on the settlement of an asset retirement obligation when the State of Louisiana returned a deposit on a well that had been plugged and abandoned when acquired, the obligation on which we had assumed at acquisition as compared to a 2012 loss of $116,394 for the plugging and abandonment of two wells
(8) Attributable primarily to stock compensation expense associated with the granting of options to directors related to the Mesa transaction; the increased use of engineering, land, and accounting consultants; and expenses associated with the Acquisition.

Operating expenses expressed in BOE for the nine months ended September 30, 2013 and 2012 are set forth in the table below:

	Three Months Ended September 30, 2013	2012	Difference	Percentage Change
Costs and Expenses				
Lease operating expense	$30.44	$19.61	$10.83	55.2 %
Production and ad valorem taxes	7.31	7.87	(0.56)	-7.2 %
Environmental remediation expense	—	1.30	(1.30)	-100.0
Exploration expense	1.74	1.24	0.50	40.7 %

Dry hole expense	16.73	—	16.73	N/A
Depletion, depreciation, amortization, and impairment expense	9.96	6.46	3.50	54.2 %
Loss on sale of oil and gas properties	0.36	—	0.36	N/A
(Gain) loss on settlement of asset retirement obligation	(0.01)	0.62	(0.63)	-101.4 %
General and administrative expense	21.80	13.51	7.30	54.0 %
Total operating expenses	$88.33	$50.61	$36.73	72.6 %

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Operating (income) loss. As a result of the above described revenues and expenses, we incurred an operating loss of $1,716,004 in the nine months ended September 30, 2013 as compared to operating income of $164,687 in the nine months ended September 30, 2012.

Interest expense. Interest expense increased to $649,655 for the nine months ended September 30, 2013, from $418,078 for the nine months ended September 30, 2012. The increase was primarily attributable to amortization of discount on notes payable, as well as interest on the notes themselves, associated with a private placement of securities and interest expense on premium financed insurance notes. In addition, the cash balance on our credit facility of $8.372,693 is higher at September 30, 2013 than the balance of $5,195,963 at September 30, 2012.

Unrealized gain (loss) on changes in derivative value. The unrealized loss on change in derivatives – commodity contracts for the nine months ended September 30, 2013, was $455,561. Unrealized loss on change in derivatives – commodity contracts for the nine months ended September 30, 2012, was $938,606. The unrealized losses in the three months ended September 30, 2013 and 2012 were the result of the change in value of the net derivative liability from that of the prior reporting period. The values underlying the derivatives are estimates of predicted future commodity prices based on current market activity and projections of future market activity. Additional contributors to fluctuations in the value of the recognized net liability are additions to and unwindings of hedged positions during any reporting period. An unrealized loss on change in derivatives – convertible debt of $536,422 was incurred during the nine months ended September 30, 2012; but no convertible debt existed during the nine months ended September 30, 2013.

Realized gain on changes in derivatives – commodity contracts. Cash settlements from hedging our sales of oil and gas production were $252,146 in the nine months ended September 30, 2013 as compared to $363,753 in the nine months ended September 30, 2012. The decrease is attributable to the same factors that affect the unrealized gains or losses associated with our commodity derivative contracts.

Loss on modification of offering. A loss on the modification of a prior offering of shares and warrants of $65,749 was incurred during the nine months ended September 30, 2013. The loss was the result of a change in fair value of shares and warrants issued in relation to the funds raised as well as a decrease in the exercise price of the warrants issued in conjunction with the offering prior to the modification. No such loss occurred during the nine months ended September 30, 2012.

Bargain purchase gain. A gain of $1,455,879 was recognized during the nine months ended September 30, 2012, on the Acquisition due to the excess fair value of net assets acquired of $15,837,220 over the purchase price of $14,381,341. No such gain occurred during the nine months ended September 30, 2012.

Income tax benefit (expense). State and federal income tax benefit for the nine months ended September 30, 2013 was $1,637,592 compared to income tax expense of $272,164 in the nine months ended September 30, 2012. The income tax benefit in the nine months ended September 30, 2013 is primarily attributable to the dry hole expense associated with drilling costs of the Thomas #6H well. The income tax expense in the nine months ended September 30, 2012, is attributable to net income during that period.

Net loss. Due to the reasons set forth above, our net loss for the nine months ended September 30, 2013 was $1,743,298 ($0.04 per basic and diluted common share). Our net income for the nine months ended September 30, 2012 was $164,687 ($0.00 per basic and diluted common share).

Liquidity and Capital Resources

Overview

As of September 30, 2013, we had a working capital deficit of $7,726,016. As of December 31, 2012, we had working capital of $5,649,632. The decrease in the working capital was attributable to:

- Decreased revenues from oil and gas sales.
- Capital expenditures on our producing properties, drilling costs in Oklahoma, transaction expenses associated with our business combination, and increased general and administrative expenses associated with additional staff and use of consultants as well as additional software and equipment to support our operations.
- The reclassification of $8,372,693 of long term debt to current portion of long term debt owed to F&M Bank due to the maturity date of the loan falling within one year of the balance sheet date.

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The Company's executive management team is working diligently to complete an all-inclusive financing package that would not only allow for significant new development in the Company's south Louisiana fields but would also provide capital to initiate drilling activities in both its Oklahoma and Wyoming project areas. The Company may close this financing initiative in late November 2013 and will initiate new development activities in the Lake Hermitage Field shortly thereafter. Drilling in the Oklahoma and Wyoming project areas is expected to begin as soon as final land title review, location selection and well planning allow. The significant increase in capital availability that is expected to come from this financing package would give the Company the ability to develop its proved reserves in its south Louisiana fields at a much faster rate than would result from financing the work solely out of cash flow. There can be no assurances, however that this new financing package will be completed.

Should a definitive agreement not be reached on the all-inclusive financing package, the Company expects to be able to continue its operations out of cash flows by scaling back on new developmental and exploratory projects in Louisiana, Oklahoma, and Wyoming while seeking additional sources of funding for those projects. In addition, the Company expects to extend the maturity date of its loan with F&M Bank at the next redetermination date (April 1, 2014) which is prior to the current maturity date of July 22, 2014 or to refinance the facility with an alternate lender. The Company cannot assure that it will be able to refinance and extend this loan, however, or refinance with an alternate lender.

Cash and Accounts Receivable

At September 30, 2013, we had cash and cash equivalents of $1,011,331, compared to $5,884,649 at December 31, 2012. Cash decreased by $4,873,318 due to payments for capital expenditures and workovers on our producing properties, drilling costs in Oklahoma, principal and interest payments on debt, transaction expenses associated with our business combination, and increased general and administrative expenses associated with additional staff and use of consultants as well as additional software and equipment to support our operations.

Liabilities

Accounts payable and accrued expenses decreased by $485,348 to $1,314,531 at September 30, 2013, from $1,799,879 at December 31, 2012, primarily due to payments of invoices associated with workovers and recompletions in our Louisiana operating area.

As of September 30, 2013, the outstanding balance of principal on debt, net of discount, was $9,024,732, a net decrease of $261,648 from the outstanding balance of $9,286,380, as of December 31, 2012. The decrease was due to the issuance of $655,000 of notes payable associated with a private placement of debt issued in the first quarter of 2013, net of amortized discount at September 30, 2013, of $143,138, and increases in premium financed insurance notes of $205,732 and the note payable to Geokinetics, Inc. of $1,384,189 net of payments of principal on notes of $2,372,630.

Cash Flows

For the nine months ended September 30, 2013 the net cash used in operating activities was $9,775 compared to net cash provided by operating activities for the nine months ended September 30, 2012 of $2,370,920, a net increase in cash used of $2,380,695. This is attributable, to our decreases in working capital and cash, transaction expenses associated with our business combination, and increased general and administrative expenses associated with additional staff and use of consultants as well as additional software and equipment to support our operations.

For the nine months ended September 30, 2013 and 2012, net cash used in investing activities was $2,840,428 and $2,233,745, respectively, an increase in cash used of $606,683. This is attributable to our geological and geophysical expense incurred in evaluating our Wyoming, Oklahoma, and Louisiana properties for drilling potential and other activities intended to increase our reserves base and drilling and recompletion activities and facilities enhancements during the nine months ended September 30, 2013.

For the nine months ended September 30, 2013 and 2012, net cash used in financing activities was $2,023,115 and $461,882 respectively, an increase in cash used of $1,561,233. This was primarily attributable to paying down principal on our credit facility with F & M Bank, retiring our note with Geokinetics, and payments made on the purchase of software net of proceeds received after the Acquisition associated with a private placement of securities that commenced on March 20, 2013.

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Subsequent Events

Effective October 1, 2013, we entered into the Second Amendment to the Loan Agreement with F&M Bank dated July 22, 2011 as previously amended on September 21, 2012 (the "Amendment"). The Amendment provides for the reduction of the borrowing base under the Loan Agreement by $675,000 to $12,700,000 from $13,375,000; resets monthly repayments of principal to $50,000 per month until the next scheduled redetermination to occur on or about April 1, 2014, and requires that general and administrative expense not exceed 27% of revenue for any two consecutive quarters.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Not required under Regulation S-K for "smaller reporting companies."

Item 4. Controls and Procedures

a) Evaluation of disclosure controls and procedures.

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of September 30, 2013. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Based on management's evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as a result of the material weaknesses described below, as of September 30, 2013, our disclosure controls and procedures are not presently designed at a level to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The material weaknesses, which relate to internal control over financial reporting, that were identified are:

1. As of September 30, 2013, we did not adequately segregate, or mitigate the risks associated with, incompatible functions among personnel to reduce the risk that a potential material misstatement of the financial statements would occur without being prevented or detected. Accordingly, management concluded that this control deficiency constituted a material weakness.

We are committed to improving our accounting and financial reporting functions. As part of this commitment, we are considering the engagement of additional employees and have engaged consultants to assist in the preparation and filing of financial reports.

We will continue to monitor and evaluate the effectiveness of our disclosure controls and procedures and our internal controls over financial reporting on an ongoing basis and are committed to taking further action and implementing additional enhancements or improvements, as necessary and as funds allow.

(b) Changes in internal control over financial reporting.

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes. During the nine months ended September 30, 2013, we discontinued the outsourcing of our oil and gas transactional accounting, implemented an enterprise resource planning system in-house, added a Controller to our accounting staff, and engaged the services of a third party information technology firm to manage our network and ensure it operates with appropriate controls.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are currently not a party to any material legal proceedings or claims.

Item 1A. Risk Factors

For information regarding risk factors, please refer to the Company's 424(b)(2) prospectus filed with the SEC on March 18, 2013, which may be accessed via EDGAR through the Internet at www.sec.gov.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Description
10.1*	Second Amendment to Loan Agreement dated October 1, 2013 by and among the Registrant, Mesa Energy, Inc., TNR Natural Resources, LLC, Mesa Gulf Coast, LLC and The F&M Bank & Trust Company
10.2*	Agreement to sell properties in Young County, Texas dated October 1, 2013 by and between the Registrant and Energy Management Resources, LLC
31.01*	Certification of Chief Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02*	Certification of Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01**	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.02**	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101INS*	XBRL Instance Document
101SCH*	XBRL Schema Document
101CAL*	XBRL Calculation Linkbase Document
101LAB*	XBRL Labels Linkbase Document
101PRE*	XBRL Presentation Linkbase Document

101DEF*	XBRL Definition Linkbase Document
*	Filed herewith.
**	This certification is being furnished and shall not be deemed “filed” with the SEC for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except if and to the extent that the Registrant specifically incorporates it by reference.

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SIGNATURES

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

	ARMADA OIL, INC.	
Date: November 14, 2013	By:	/s/ RANDY M. GRIFFIN Randy M. Griffin Chief Executive Officer (Principal Executive Officer)
Date: November 14, 2013	By:	/s/ RACHEL L. DILLARD Rachel L. Dillard Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)