Armada Oil, Inc.
Form 10-K
March 31, 2014

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2013

Commission file number: 000-55128

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

Nevada (State or other jurisdiction of incorporation or organization)	98-0195748 (IRS Employer Identification No.)
5220 Spring Valley Road, Suite 615 Dallas, Texas (Address of principal executive office)	75254 (Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 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 x

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

The aggregate market value of the voting common equity held by non-affiliates as of June 28, 2013, based on the closing sales price of the Common Stock as quoted on the OTC Markets was approximately $12,075,703. For purposes of this computation, all officers, directors, and 5 percent beneficial owners of the registrant are deemed to be affiliates. Such determination should not be deemed an admission that such directors, officers, or 5 percent beneficial owners are, in fact, affiliates of the registrant.

As of March 28, 2014, there were 56,030,473 shares of registrant's common stock outstanding.

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PART I

ITEM 1. BUSINESS

Forward Looking Statements

This Annual Report on Form 10-K (including the section regarding Management's Discussion and Analysis of Financial Condition and Results of Operations) contains forward-looking statements regarding our business, financial condition, results of operations and prospects. Words such as "expects," "anticipates," "intends," "plans," "believes," "seeks," "estimates" and similar expressions or variations of such words are intended to identify forward-looking statements, but are not deemed to represent an all-inclusive means of identifying forward-looking statements as denoted in this Annual Report on Form 10-K. Additionally, statements concerning future matters are forward-looking statements.

Although forward-looking statements in this Annual Report on Form 10-K reflect the good faith judgment of our Management, such statements can only be based on facts and factors currently known by us. Consequently, forward-looking statements are inherently subject to risks and uncertainties and actual results and outcomes may differ materially from the results and outcomes discussed in or anticipated by the forward-looking statements. Factors that could cause or contribute to such differences in results and outcomes include, without limitation, those specifically addressed under the heading "Risks Factors" below, as well as those discussed elsewhere in this Annual Report on Form 10-K. Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this Annual Report on Form 10-K. We file reports with the Securities and Exchange Commission ("SEC"). We make available on our website under "Investor Relations/SEC Filings," free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file such materials with or furnish them to the SEC. Our website address is www.armadaoil.us. You can also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You can obtain additional information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

We undertake no obligation to revise or update any forward-looking statements in order to reflect any event or circumstance that may arise after the date of this Annual Report on Form 10-K. Readers are urged to carefully review and consider the various disclosures made throughout the entirety of this annual Report, which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operations and prospects.

This Annual Report on Form 10-K includes the accounts of Armada Oil, Inc. and its wholly-owned subsidiaries, Armada Oil and Gas, Inc. (“AOG”), Armada Operating, LLC (“AOP”), Mesa Energy, Inc. (“MEI”), Mesa Gulf Coast, LLC (“MGC”), Tchefuncte Natural Resources, LLC (“TNR”), Mesa Midcontinent LLC (“MMC”), Armada Midcontinent, LLC, formerly known as MMC Resources, LLC (“AMC”), and TNR Holdings, LLC (“TNRH”) (MEI owns 65.625% of this subsidiary), collectively referred to as “we”, “us,” “our,” “Armada” or the "Company".

For definitions of certain oil and gas industry terms used in this Annual Report on Form 10-K, please see the Glossary beginning on page 16.

Overview of Our Business

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;
- Turkey Creek Field, an area of interest in which we hold undeveloped leasehold interests and a farm-out in Garfield and Major Counties, Oklahoma;
- Bear Creek Prospect, where we hold a farmout agreement with Anadarko on approximately 9,800 mineral acres in Carbon County, Wyoming; and
- Java Field, a natural gas development project in Wyoming County in western New York.

History

Armada Oil, Inc. (the "Company") 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 (the "Mesa Acquisition") 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 four 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. On December 16, 2013, MEI formed TNR Holdings, LLC ("TNRH"), a Delaware limited liability company as a wholly owned subsidiary, and contributed its member's capital in TNR and MGC to TNRH. On December 20, 2013, the Company entered into a Unit Purchase Agreement with Gulfstar Resources, LLC, ("Gulfstar") pursuant to which Gulfstar contributed $6,250,000 of capital in exchange for 6,250 Class A Units of TNRH membership interest at a price of $1,000 per Class A Unit, representing a 34.375% membership interest in TNRH ("Tranche A"). Gulfstar is obligated to purchase an additional aggregate 11,873 Class A Units of TNRH at a price of $564.31 per Class A Unit ($6,700,053 in the aggregate), representing an additional 25.925% membership interest in TNRH by April 1, 2014 ("Tranche B"), and has an option to purchase up to an additional 9,718 Class A Units, at one or more additional closings, at a price of $468.20 per Class A Unit ($4,549,968 in the aggregate), representing an additional 9.7% membership interest in TNRH ("Tranche C" and together with Tranche A and Tranche B, the "Gulfstar Transaction"). 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. Our operating entities have historically employed, and will continue in the future to employ, on an as-needed basis, the services of drilling and recompletion contractors, other drilling related vendors, field service companies and professional petroleum engineers, geologists and landmen (to the extent that they are not on staff) as required in connection with future drilling and production operations.

On March 14, 2014, Armada Midcontinent, LLC, (formerly known as MMC Resources, LLC), a wholly owned subsidiary of MEI, entered into a purchase and sale agreement with Piqua Petro, Inc., pursuant to which we will purchase from Piqua Petro its interests in six oil and gas leases covering approximately 1,040 acres in Woodson County, Kansas. We will pay the seller $6,500,000 in cash for the leases (subject to an adjustment in our favor for production revenue received by the seller for production from and after March 1, 2014, and an adjustment in favor of the seller for its operating costs on and subsequent to March 1, 2014). We have paid a $100,000 non-refundable earnest money deposit and will pay the balance at closing, which both we and the seller are obligated to use best efforts to effect by April 3, 2014. The capital to be used for closing is expected to come from the closing of Tranche B of the Gulfstar Transaction. We will acquire 100% of the leasehold working interest in the lands covered by the leases, subject to royalties, overriding royalties and other expense-free burdens on production that do not exceed 12.5% of 8/8ths, such that the net revenue interest in the leases conveyed to us will not be less than 87.5%. The agreement contains certain indemnification and other customary provisions.

Upon closing and funding of Tranche B of the Gulfstar Transaction, MEI’s interest in TNR Holdings, LLC will be reduced to 39.7%.

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General Philosophy

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. We expect this approach to result in steady reserve growth, strong earnings, and significant capital appreciation.

Our philosophy has been to operate, or directly control the operation of, through our wholly-owned subsidiaries or their designees, all properties that we own or acquire. In our opinion, the lack of control resulting from leaving operational control in the hands of third parties substantially increases the risks associated with oil and gas drilling, development and production. Although the Gulfstar Transaction is expected to result in us having a minority interest in TNRH, the transaction will enable us to reallocate our asset base to other areas which we believe will ultimately be more productive. There will always be exceptions dictated by specific circumstances, but our philosophy as outlined above has not changed.

We plan for our portfolio to consist of a balanced and diversified mix of multiple asset components that include current production, multiple recompletion and enhancement opportunities along with developmental drilling opportunities. We expect that the production acquisition component in our business plan should expand an already strong revenue base resulting in long-term, dependable revenue and stability. The developmental drilling program, we believe, should provide a relatively low risk method of achieving rapid and repeatable growth in revenue and reserves.

Various federal and state regulations regarding the discharge of materials into the environment are applicable to our operations. We maintain strict compliance with these regulations and endeavor to do all we can to make certain that the environment is protected in and around our operations. The cost of environmental control facilities and efforts is included as a line item in the budget of each operation as appropriate. We anticipate no extraordinary capital expenditures for environmental control facilities related to any of our existing operations for the current fiscal year.

Our Properties

The table below lists and summarizes our acreage by area as of December 31, 2013. This table excludes acreage in which our interests are limited to royalty and overriding royalty interests.

The Company holds oil and gas lease interests in Louisiana, New York, and Oklahoma. The approximate acreage in each property is outlined in the table below. The Company evaluates each of its properties upon completion of drilling and assessment of reserves to either classify the properties as "properties subject to amortization" or impair them.

Area	Developed Acreage		Undeveloped Acreage		Total Acreage		Weighted Average Remaining Lease Term
	Gross	Net	Gross	Net	Gross	Net	
Louisiana	$ 6,920.20	$ 6,833.80	$ 348.90	$ 261.68	$ 7,269.10	$ 7,095.48	Life of Production
New York	2,851.50	2,851.50	0.00	0.00	2,851.50	2,851.50	Life of Production
Oklahoma	0.00	0.00	2,230.82	1,965.23	2,230.82	1,965.23	1.2 Years
Total	9,771.70	9,685.30	2,579.72	2,226.91	12,351.42	11,912.21	

Louisiana Area

On December 20, 2013, the Company's wholly owned subsidiary, MEI, completed an asset reallocation financing transaction with Gulfstar. As part of the transaction, MEI formed a new limited liability company, TNRH, and contributed to TNRH MEI's 100% membership interest in each of TNR and MGC. As of December 31, 2013, MEI's membership interest in TNRH is 65.625%. TNR, now a wholly owned subsidiary of TNRH, owns 100% working interests in the Lake Hermitage Field in Plaquemines Parish, Louisiana along with various working interests in producing properties the Valentine and Larose Fields in Lafourche Parish, Louisiana and the Bay Batiste Field in Plaquemines Parish, Louisiana.

The additional capital provided by Tranche A of the Gulfstar Transaction is expected to accelerate development of the Company's south Louisiana reserves.

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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'. It is situated in a shallow, marshy environment on the west side of the Mississippi River.

TNR owns a 100% working interest and an approximate 75% net revenue interest in each of the eighteen wells in the Lake Hermitage Field. A total of 3,589 mineral acres are held by production in the field. Seven wells are currently shut-in pending evaluation for workover and/or future recompletion in uphole zones, and an additional well has been converted to a salt water disposal well which is expected to 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 January 2013, MGC completed a successful workover of the LLDSB #10 well in Lake Hermitage Field 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. In December 2013, MGC completed successful workovers of the LLDSB #4 and LLDSB #30 wells that resulted in additional increases in production of approximately 80 barrels of oil per day. Furthermore, an extensive geological and engineering evaluation of the field is ongoing, and thirty-nine potential drilling locations have been evaluated, five of which are proved undeveloped ("PUD") locations with multiple stacked pay zones.

Lake Hermitage Field

- Operated Wells: 10 Producing Oil and Gas Wells and 8 Shut-in Oil and Gas Wells, one of which has recently been converted to a salt water disposal well
- Non-Operated Wells: None
- Reservoir Thickness: Each productive sand is 35' – 142' thick
- Producing Depth: 10,750' – 14,600'
- Drilling Method: Vertical and Directional
- Production Characteristics: 4 – 10+ years of production from each horizon and liquid condensation associated with the natural gas reservoirs which have high Btu, reserve calculations are done by decline-curve analysis

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.

TNR owns approximately 3,082 net mineral acres that are held by production in the field and holds working interests that range from 68% to 100% with net revenue interests from 51% to 82.4%.

Twenty of the thirty-eight 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.

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.

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Valentine Field

- Operated Wells: 15 Producing Gas and Oil Wells; 3 Active Salt Water Disposal Wells; and 20 Shut-in Gas and Oil Wells
- Non-Operated Wells: None
- Reservoir Thickness: Each productive sand is 10’ – 195’ thick
- Producing Depth: 9,700’ – 13,400’
- Drilling Method: Vertical and Directional
- Production Characteristics: 4 – 10+ years of production from each horizon and liquid condensation associated with the natural gas reservoirs which have high Btu, reserve calculations are done by decline-curve analysis

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 separates the field into three main producing segments.

TNR owns various working interests that range from 10.4% to 100% and net revenue interests from 8.7% to 72.3% 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.

Larose Field

- Operated Wells: 1 Producing Oil Well and 1 Active Salt Water Disposal Well
- Non-Operated Wells: 1 Producing Oil and Gas Well; 1 Active Salt Water Disposal Well; and 4 Shut-in Gas Wells
- Reservoir Thickness: Each productive sand is 10’ – 55’ thick
- Producing Depth: 11,000’ – 16,200’
- Drilling Method: Vertical and Directional
- Production Characteristics: 5+ years of production from each horizon and liquid condensation associated with the natural gas reservoirs which have high Btu, reserve calculations are done by decline-curve analysis

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.

TNR owns various working interests that range from 26.8% to 100% and net revenue interests from 19.43% to 77% in seven wells in the Bay Batiste Field. One well is currently producing and the other five 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.

Bay Batiste Field

- Operated Wells: 1 Producing Gas Well; 1 Active Salt Water Disposal Well; and 5 Shut-in Gas Wells
- Non-Operated Wells: None
- Reservoir Thickness: Each productive sand is 30’ – 85’ thick
- Drilling Depth: 14,000’ – 14,500’
- Drilling Method: Vertical and Directional
- Production Characteristics: 4 – 10+ years of production from each horizon and liquid condensation associated with the natural gas reservoirs which have high Btu, reserve calculations are done by decline-curve analysis

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New York Area

The New York Area is located in the Java Field in Wyoming County, New York.

Java Field – Wyoming County, New York

MEI operates 19 producing gas wells and a 12.4 mile pipeline and gathering system in the Java Field with an approximate 78% net revenue interest in leases covering 2,851.5 gross and net acres, more or less.

Production is nominal from the wells but serves to hold the acreage for future development. In late 2009, we evaluated a number of the existing wells in order to determine the viability of the re-entry of existing vertical wellbores for plug-back and recompletion of the wells in the Marcellus Shale. The Marcellus Shale is approximately 1,240’ above the productive Medina Formation in the Java Field. As a result of this evaluation, we selected the Reisdorf Unit #1 well and the Ludwig #1 well as our initial targets and these two wells were recompleted in the Marcellus Shale and fracked in May and June of 2010. 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. However, the State of New York has placed a moratorium on high volume frac stimulation in order to develop new permitting rules. The new permitting rules have not been completed and there can be no assurance when such permitting rules will be issued or what restrictions such permits might impose on producers. Accordingly, we are 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.

Java Field

- Operated Wells: 19 Producing Gas Wells
- Non-Operated Wells: None
- Reservoir Thickness: The Medina Sandstone averages 82’ thick and the Marcellus Shale averages 105’ thick
- Producing Depth: 2,850’ – 3,500’
- Drilling Method: Vertical
- Production Characteristics: With 25+ years of production from each horizon, rates and pressure data support the reserve calculations which are done by decline-curve analysis
- Key Considerations: Understanding the effective drainage area of each well supports the exploitation field development of the conventional producing horizons and the unconventional shale horizons in Java Field

Oklahoma Area

The Oklahoma Area is located in Garfield and Major Counties in Oklahoma and is referred to as the Turkey Creek Project.

Turkey Creek Project - Garfield and Major Counties, Oklahoma

The Company owns 2,230.82 gross and 1,965.23 net acres of undeveloped leasehold with an average remaining lease term of approximately 1.2 years. The Mississippian Limestone in Oklahoma is a proven zone that has been drilled vertically in Oklahoma for many years so there is a lot of data available with no need for seismic. The Mississippian Limestone in the area of interest is at a vertical depth of approximately 7,000 feet and is 300 feet to 500 feet thick. The Woodford Shale, which would be a secondary objective in any well drilled, 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 would increase the potential reserves recoverable. A multi-stage frac is required using acid, fresh water and a simple sand proppant. The Mississippian produces some water, so disposal wells will be required. The oil is light, sweet crude with a gravity of 40 to 45 dg.

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 well 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 re-drill the well from the same surface location when resources allow.

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Wyoming Area

The Bear Creek Prospect – Carbon County, Wyoming

The Company holds a farmout agreement with Anadarko (Anadarko Contract) on approximately 9,800 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 before July 31, 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, EOG, Noble and other major independents.

Initial indications from those fields indicate drilling and completion costs for a horizontal well in 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%.

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 3-D seismic shoot completed in 2013.

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 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 8,500 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. A location for the Initial Test Well has been 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.

Kansas Area

On March 14, 2014, we entered into a purchase and sale agreement with Piqua Petro, Inc., pursuant to which we will purchase from Piqua Petro its interests in six oil and gas leases covering approximately 1,040 acres in Woodson County, Kansas, with total current production of approximately 80 barrels per day. We will pay the seller $6,500,000 in cash for the leases (subject to an adjustment in our favor for production revenue received by the seller for production from and after March 1, 2014, and an adjustment in favor of the seller for its operating costs on and after March 1, 2014). We have paid a non-refundable $100,000 earnest money deposit and will pay the balance at closing, which both we and the seller are obligated to use best efforts to effect by April 3, 2014. We will acquire 100% of the leasehold working interest in the lands covered by the leases, subject to royalties, overriding royalties and other expense-free burdens on production that do not exceed 12.5% of 8/8ths, such that the net revenue interest in the leases conveyed to us will not be less than 87.5%. The agreement contains certain due diligence and other conditions to closing, and there can be no assurance that those conditions will be satisfied. The agreement also contains certain indemnification and other customary provisions.

The foregoing is a summary of the material terms and conditions of the purchase and sale agreement and is qualified by reference to the agreement, a copy of which is filed as an exhibit to our Current Report on Form 8-K filed with the SEC on March 20, 2014, and which is incorporated herein by reference.

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We intend to fund the payment of the purchase price for these leases by drawing down “Tranche B” under the Unit Purchase Agreement between us and Gulfstar entered into in December 2013, under which Gulfstar is obligated to purchase an additional aggregate 11,873 Class A Units of our subsidiary TNRH at a price of $564.31 per Class A Unit ($6,700,053 in the aggregate). As a result of the first closing under the Unit Purchase Agreement, Gulfstar holds a 34.375% membership interest in TNRH; the additional funding will result in Gulfstar acquiring an additional 25.925% membership interest in TNRH, for a total of 60.3%. Subsidiaries of TNRH own a 100% working interest in the Lake Hermitage Field in Plaquemines Parish, Louisiana, along with various working interests in producing properties in three additional fields in Plaquemines and Lafourche Parishes, Louisiana and operate substantially all these working interests. A further description of the Gulfstar Transaction and related agreements is set forth in our Current Report on Form 8-K filed with the Securities and Exchange Commission on December 27, 2013, and is incorporated herein by reference.

Commodity Price Environment

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. Commodity prices are beyond our control and are difficult to predict. We currently have a portion of our production hedged for both natural gas and oil as required under our senior debt facility. More information regarding these hedges can be found in the footnotes to the financial statements contained herein.

Government Regulations

General

Our business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Most of our drilling operations will require permits or authorizations from federal, state or local agencies. Changes in any of these laws and regulations or the denial or vacating of permits could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our operations comply in all material respects with applicable laws and regulations. There are no pending or threatened enforcement actions related to any such laws or regulations. We further believe that the existence and enforcement of such laws and regulations will have no more restrictive an effect on our operations than on other similar companies in the energy industry.

Proposals and proceedings that might affect the oil and gas industry are constantly pending before Congress, the Federal Energy Regulatory Commission (“FERC”), state legislatures and commissions and the courts. We cannot predict when or whether any such proposals may become effective. The energy industry has always been heavily regulated and there is no reason to believe that the regulatory approach currently pursued by various agencies will not continue. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material adverse effect upon our capital expenditures, earnings, or competitive position.

Federal Regulation of Sales and Transportation of Natural Gas

Historically, the transportation and sale of natural gas and its component parts in interstate commerce have been regulated under several laws enacted by Congress and the regulations passed under these laws by FERC. Our sales of natural gas, including condensate and liquids, may be affected by the availability, terms, and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. From

1985 to the present, several major regulatory changes have been implemented by Congress and FERC that affect the economics of natural gas production, transportation and sales. In addition, FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. We cannot predict what further action FERC will take on these matters. Some of FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with whom we compete.

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State Regulation

Our operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing of wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells, and the disposal of fluids used and produced in connection with operations. Our operations are also subject to various conservation laws and regulations pertaining to the size of drilling and spacing units or proration units and the unitization or pooling of oil and gas properties.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory capacity requirements, but, except as noted above, does not generally entail rate regulation. These regulatory burdens may affect profitability, but we are unable to predict the future cost or impact of complying with such regulations.

Environmental Matters

Our operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, storage, and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling, production, and natural gas processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as use of pits and plugging of abandoned wells; restrictions on injection of liquids into subsurface strata that may contaminate groundwater; and impose substantial liabilities for pollution resulting from our operations. Environmental permits required for our operations may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. We believe that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws.

Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on us as well as the natural gas and crude oil industry in general. We are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under domestic or foreign federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our consolidated financial position or results of operations. Moreover, we maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," and comparable state statutes impose strict joint and several liability on certain classes of persons who are considered to have contributed to the release of a “hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed, or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is common for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment. In the course of our operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA currently contains a "petroleum exclusion" from the definition of “hazardous,” state laws affecting our operations impose cleanup liability relating to petroleum related products, including crude oil cleanups. In addition, although the Resource Conservation and Recovery Act of 1976, as amended (“RCRA”) regulations currently classify certain wastes which are uniquely associated with field operations as "non-hazardous," such exploration, development and production wastes could be reclassified by regulation as hazardous wastes thereby administratively making such wastes subject to more stringent handling and disposal requirements.

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We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of natural gas and crude oil. Although we utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990

United States federal regulations also require certain owners and operators of facilities that store or otherwise handle crude oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of crude oil into surface waters. The federal Oil Pollution Act ("OPA") contains numerous requirements relating to prevention of, reporting of, and response to crude oil spills into waters of the United States. For facilities that may affect state waters, OPA requires an operator to demonstrate $10 million in financial responsibility. State laws mandate crude oil cleanup programs with respect to contaminated soil. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

U.S. Environmental Protection Agency

U.S. Environmental Protection Agency regulations address the disposal of crude oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The RCRA provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, crude oil and natural gas wastes are regulated by the Underground Injection Control program under the Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed of at an approved hazardous waste facility. We have coverage under the applicable Clean Water Act permitting requirements for discharges associated with exploration and development activities.

Resource Conservation and Recovery Act

RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act

The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the crude oil and natural gas industry into certain coastal and offshore waters. Further, the Environmental Protection Agency has adopted regulations requiring certain crude oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for crude oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

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Safe Drinking Water Act

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from crude oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Air Pollution Control

The Clean Air Act and state air pollution laws adopted to fulfill its mandate provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

Naturally Occurring Radioactive Materials ("NORM")

NORM materials are not covered by the Atomic Energy Act. Their radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the crude oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the State of Louisiana.

Abandonment Costs

All of our crude oil and natural gas wells will require proper plugging and abandonment when they are no longer producing. As necessary, we post financial assurance deposits with regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface production site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Competition

The oil and gas industry is intensely competitive with respect to the acquisition of prospective oil and natural gas properties and oil and natural gas reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for drilling and completion of wells. Consequently, drilling equipment may be in short supply from time to time. However, drilling rigs and equipment are reasonably available at the present time in the areas where we operate.

Employees

As of December 31, 2013, we had 19 employees, including our executive officers. We anticipate the need for additional accounting, land, technical, and field personnel from time to time. Although demand for quality staff is high in the oil and gas industry, we believe we will be able to fill these positions in a timely manner.

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GLOSSARY OF OIL AND GAS TERMS

The following are the meanings of some of the oil and gas industry terms that may be used in this annual report.

2-D seismic: (two-dimensional seismic data) Geophysical data that depicts the subsurface strata in two dimensions. A vertical section of seismic data consisting of numerous adjacent traces acquired sequentially.

3-D seismic: A set of numerous closely-spaced seismic lines that provide a high spatially sampled measure of subsurface reflectivity. Events are placed in their proper vertical and horizontal positions, providing more accurate subsurface maps than can be constructed on the basis of more widely spaced 2D seismic lines. In particular, 3D seismic data provide detailed information about fault distribution and subsurface structures.

Barrel: Standard volume of measure for crude oil and liquid petroleum products.

Basin: A depression of the earth's surface into which sediments are deposited, usually characterized by sediment accumulation over a long interval; a broad area of the earth beneath which layers of rock are inclined, usually from the sides toward the center.

BCF: Billion cubic feet.

Block: Subdivision of an area for the purpose of licensing to a company or companies for exploration/production rights.

BOE: Barrel of oil equivalent. One barrel equals 42 US gallons. One/sixth of a barrel is equivalent to one MCF (thousand cubic feet) of natural gas.

BOE/D: Barrel of oil equivalent per day.

Completion: The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Crude oil: A general term for unrefined petroleum or liquid petroleum.

Defined-risk: Projects defined by multiple evaluation techniques in order to estimate more reasonably the potential for success. These techniques may include 2-D or 3-D seismic, geo-chemistry, subsurface geology, surface mapping, data from surrounding wells, and/or satellite imagery.

Developmental drilling: Drilling that occurs after the initial discovery of hydrocarbons in a reservoir.

Devonian Shale: Shale formed from organic mud deposited during the Devonian Period (416–359 million years ago).

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

E&P: Exploration and production.

Exploration: The initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well. Appraisal, development and production phases follow successful exploration.

Exploratory well: A well drilled to find and produce oil and gas reserves that is not a development well.

Fairway: A term used in the industry to describe an area believed to contain the most productive mineral acreage in a play.

Farm-out: An agreement whereby the owner of a lease (farmor) agrees to assign part or all of a leasehold interest to a third party (farmee) in return for drilling of a well or wells and/or the performance of other required activities. The farmee is said to “farm-in.”

Field: An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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Finding cost: The total cost to drill, complete and hook up a well divided by the mcf or barrels of proved reserves.

Formation: An identifiable layer of rocks named after the geographical location of its first discovery and dominant rock type.

Fracturing or "Fracking": Hydraulic fracturing is a method used to create fractures that extend from a borehole into rock formations, which are typically maintained by a proppant, a material such as grains of sand, ceramic beads or other material which prevent the fractures from closing. The method is informally called fracking or hydro-fracking. The technique of hydraulic fracturing is used to increase or restore the rate at which fluids, such as oil, gas or water, can be produced from the desired formation. By creating fractures, the reservoir surface area exposed to the borehole is increased.

Gas show: While drilling a well through different rock formations, gas may appear in the drilling mud which is circulating through the drill pipe, which indicates the presence of gas in the formation being drilled; drillers call this a "gas show".

Hamilton Group: A bedrock unit in New York, Pennsylvania, Maryland and West Virginia; the oldest strata of the Devonian gas shale sequence. In the interior lowlands of New York, the Hamilton Group contains the Marcellus, Skaneateles, Ludlowville, and Moscow Formations, in ascending order, with the Tully Limestone above.

Horizontal well: a well in which the borehole is deviated from vertical at least 80 degrees so that the borehole penetrates a productive formation in a manner parallel to the formation. A single horizontal lateral can effectively drain a reservoir and eliminate the need for several vertical boreholes.

Hydrocarbon: A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane [CH 4], but many are highly complex molecules, and can occur as gases, liquids or solids. The molecules can have the shape of chains, branching chains, rings or other structures. Petroleum is a complex mixture of hydrocarbons. The most common hydrocarbons are natural gas, oil and coal.

Lead: a possible prospect.

Marcellus Shale: The lowest unit of the Devonian age Hamilton Group; a unit of marine sedimentary rock found in eastern North America. Named for a distinctive outcrop near the village of Marcellus, New York, it extends throughout much of the Appalachian Basin. The shale contains largely untapped natural gas reserves, and its proximity to the high-demand markets along the East Coast of the United States makes it an attractive target for energy development.

MCF: Standard measure of volume for natural gas which is one thousand cubic feet.

MCFE: Six thousand cubic feet of natural gas is equivalent to one barrel of oil.

MCFE/D: MCF equivalent per day.

Medina Sandstone: The Lower Silurian age Medina Group sandstones comprise the dominant tight gas sandstone play in western and southwestern New York. Depths vary from 1,800 feet in the west central part of the state to 4,500 feet in the western part of the state.

Net revenue interest (NRI): The portion of oil and gas production revenue remaining after the deduction of royalty and overriding royalty interests.

NYMEX: The New York Mercantile Exchange, the world's largest physical commodity futures exchange, located in New York City.

Operator: The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

Overriding royalty interest (ORRI): an interest carved out of the lessee’s working interest that entitles its owner to a fraction of production free of any production or operating expense, but not free of production or severance tax levied on the production. An overriding interest’s duration derives from the lease in which it was created.

Participation interest: The proportion of exploration and production costs each party will bear and the proportion of production each party will receive, as set out in an operating agreement.

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Play: A group of oil or gas fields or prospects in the same region that are controlled by the same set of geological circumstances.

Production: The phase that occurs after successful exploration and development and during which hydrocarbons are drained from an oil or gas field.

Prospect: A specific geographic area, which based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Recompletion: After the initial completion of a well, the action and technique of re-entering the well and repairing the original completion or completing the well in a different formation to restore the well's productivity.

Reservoir: A subsurface, porous, permeable rock formation in which oil and gas are found.

Royalty interest: An ownership interest in the portion of oil, gas and/or minerals produced from a well that is retained by the lessor upon execution of a lease or to one who has acquired possession of the royalty rights, based on a percentage of the gross production from the property free and clear of all costs except taxes.

Seismic: Pertaining to waves of elastic energy, such as that transmitted by P-waves and S-waves, in the frequency range of approximately 1 to 100 Hz. Seismic energy is studied by scientists to interpret the composition, fluid content, extent and geometry of rocks in the subsurface. "Seismic," used as an adjective, is preferable to "seismics," although "seismic" is used commonly as a noun.

Shale: A fine-grained sedimentary rock composed of flakes of clay minerals and tiny fragments of other minerals, especially quartz and calcite. Shale is characterized by thin laminate, or parallel layering or bedding less than one centimeter in thickness.

Shut in: Not currently producing.

Theresa Sandstone: An Upper Cambrian age sandstone underlying most of western New York at depths ranging from 3,000 feet to 13,000 feet. Theresa wells are typically drilled to depths ranging from 5,000 feet to 7,000 feet.

Twin well: A well drilled on the same location as another well or closely offsetting it.

Working interest: The interest in oil or gas that includes the responsibility for all drilling, developing and operating costs.

Workover: The performance of one or more of a variety of remedial operations on a producing well to try to increase or restore production.

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ITEM 1A. RISK FACTORS

Risks Relating to Our Business:

If we are unable to generate or obtain sufficient capital to fund our capital budgets, business operations could be harmed and if we do obtain additional capital in the form of equity financing, existing shareholders could suffer substantial dilution.

We currently anticipate that we will require approximately $4,500,000 to adequately fund our current drilling and recompletion budget for 2014. We expect those funds to come from an equity injection as a result of the Gulfstar transaction as well as from cash flow generated from operations. To the extent cash flow from operations is insufficient; we expect to draw on cash reserves and additional borrowings on our senior credit facility. To the extent that we pursue additional acquisitions or choose to drill additional wells, which is a distinct possibility, additional capital would likely be required. There can be no assurance that additional financing will be available for those activities in amounts or on terms acceptable to us. An inability to obtain additional capital could restrict our ability to acquire additional properties and implement our business plan. Any additional equity financing could involve substantial dilution to then existing shareholders.

Our current lack of diversification could increase the risk of an investment in our company.

Our business focus is on the oil and gas industry in a limited number of geographic areas, currently in south Louisiana, Oklahoma, western New York, and Wyoming. Larger companies have the ability to manage their risk by geographic diversification. It is our intent to pursue opportunities in other geographic areas as those opportunities present themselves as is discussed above. However, we may continue to have a lack of diversification for the near future. As a result, we could be impacted more acutely by factors affecting our industry in the regions in which we operate than we would if our business were more diversified, thereby enhancing our risk profile. If we do not diversify our operations, our financial condition and results of operations could be negatively impacted.

Future investment in drilling projects will increase the risks inherent in our oil and gas activities and our drilling operations may not be successful.

We intend to develop a portfolio consisting of a balanced and diversified mix of existing production and developmental drilling opportunities. Some drilling projects are more exploratory in nature, and those projects come with greater risks than in acquisitions and developmental drilling. Whether developmental or exploratory all drilling comes with risk, both geological and mechanical, and there is no assurance that these activities will be successful or that we will discover meaningful levels of reserves. We cannot be sure that an overall drilling success rate or production operations within a particular area will ever come to fruition and, in any event, production rates inevitably decline over time. We may not recover all or any portion of the capital investment in our wells or the underlying leaseholds. Unsuccessful drilling activities would have a material adverse effect upon our results of operations and financial condition.

Investment in developmental drilling and/or recompletion of existing wells in south Louisiana does not come without risk.

Additionally, there are significant uncertainties as to the future costs and timing of drilling and completing new wells and/or recompleting existing wells. Our drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;

- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment or materials.

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Because we may not operate all of our properties, we could have limited influence over their development.

Although we intend to operate or otherwise directly control the operation of all our properties, there may be certain situations wherein we acquire non-operated properties as part of an acquisition package or elect to allow others to operate. In that event, we would have limited influence over the operations of those properties. Our lack of control could result in the following:

- the operator may initiate exploration or development on a faster or slower pace than we prefer;
- the operator may propose to drill more wells or build more facilities on a project than we have budgeted for or that we deem appropriate, which may mean that we are unable to participate in the project or share in the revenues generated by the project even though we paid our share of the initial exploration costs.

Either of these events could materially reduce the value of our properties.

Drilling initiatives on the “Bear Creek” project may not prove successful.

We hold a farmout agreement with Anadarko relating to the Bear Creek project located in Carbon County, Wyoming. Our primary initiative for the Bear Creek project is to identify and exploit resources from potential sandstone reservoirs in the Niobrara Formation. There is no guarantee that our efforts on Bear Creek project will ever produce commercial volumes of oil or gas, which could have a material adverse effect upon our results of operations.

Drilling Initiatives in the Turkey Creek Field may not prove successful.

Our initial drilling effort in the Turkey Creek Field was unsuccessful due to mechanical failure. The geological data obtained in the effort, however was very encouraging. We expect to continue our drilling program in the field when resources are available to do so. However, there is no guarantee that resources will become available to continue the effort or that our efforts in the Turkey Creek Field will ever produce commercial volumes of oil or gas, which could have a material adverse effect upon our results of operations.

Drilling initiatives in the Java Field may not prove successful.

The primary target for production of natural gas in our Java Field property is the Marcellus Shale. The amount of natural gas that can be commercially produced from any shale gas reservoir depends upon the rock and shale formation quality, the original free gas content of the shales, the thickness of the shales, the reservoir pressure, the rate at which gas is released from the shales, the existence of any natural fractures through which the gas can more easily flow to the well bore and the success of the hydraulic fracturing of the formation.

There is no guarantee that the potential drilling locations we now have or may acquire in the future will ever produce commercial volumes of natural gas, which could have a material adverse effect upon our results of operations.

We do not own all of the land on which our pipelines are located or on which we may seek to locate pipelines in the future, which could disrupt our operations and growth.

We do not own the land on which our pipelines have been constructed, but we do have right-of-way and easement agreements from landowners, some of which may require annual payments to maintain the agreements and most of which have a perpetual term. New pipeline infrastructure construction may subject us to more onerous terms or to increased costs if the design of a pipeline requires redirecting. Such costs could have a material adverse effect on our business, results of operations and financial condition.

Pending New York legislative initiatives and environmental studies of the effect of hydraulic fracturing may limit our exploration and developmental efforts in the Marcellus Shale in New York.

The New York Department of Environmental Conservation is currently engaged in an environmental review of the impacts of hydraulic fracturing in New York. Until such time as this review has been completed, New York has imposed a moratorium on high volume hydraulic fracturing. Additionally, bills have been introduced in the New York state legislature that, if enacted, could result in the imposition of a permanent moratorium on hydraulic fracturing operations in the state. The imposition of such a moratorium or any negative outcome of an environmental study leading to restrictions, limitations or prohibitions on hydraulic fracturing in New York could limit our exploration and developmental efforts in the Marcellus shale.

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If we are unable to continue to retain the services of Randy M. Griffin and/or, Rachel L. Dillard or if we are unable to successfully recruit qualified managerial and field personnel having experience in oil and gas exploration, our operations could suffer.

Success depends to a significant extent upon the continued services of Randy M. Griffin, our Chief Executive Officer, and Rachel L. Dillard, our Chief Financial Officer. Loss of the services of either of these officers could have a material adverse effect on growth, revenues and prospective business. We currently do not have key-man insurance covering either of these officers. In order to successfully implement and manage our business plan, we will be dependent upon, among other things, successfully recruiting qualified managerial and field personnel having experience in the oil and gas development and production business. Competition for qualified individuals is intense. There can be no assurance that we will be able to find and attract new employees and retain existing employees or that we will be able to find, attract and retain qualified personnel on acceptable terms.

Our directors and executive officers control a significant portion of our stock and, if they choose to vote together, would have sufficient voting power to have a significant impact on substantially all corporate matters.

As of March 31, 2014, our directors and executive officers beneficially owned approximately 23.8% of our outstanding common stock in the aggregate. Our directors and executive officers, in their capacities as stockholders, may have significant influence over our policies and affairs, including the election of future directors. Should they act as a group, they would have substantial influence over the election of all of our directors and all other corporate matters.

We may have difficulty managing growth in our business.

Because of the relatively small size of our company, growth in accordance with our long-term business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As we increase our activities and the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the recruitment and retention of required personnel could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Risks Relating to Our Industry:

We may not be able to develop oil and gas reserves on an economically viable basis and our reserves and production may decline as a result.

To the extent that we succeed in discovering additional oil and/or natural gas reserves, we cannot assure that these reserves will be capable of production levels that are commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and natural gas reserves. Without the addition of reserves through acquisition, exploration or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets.

Future oil and gas exploration may involve unsuccessful efforts, not only from dry holes, but from wells that are marginally productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and mechanical conditions. While we will endeavor to effectively manage these conditions, they cannot be totally eliminated and could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

Estimates of oil and natural gas reserves that we make may be inaccurate and our actual revenues may be lower than our financial projections.

We make estimates of oil and natural gas reserves using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, other capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. We depend to a significant degree on third-party engineering firms to evaluate our properties.

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In addition, economic factors beyond our control such as interest rates and commodity prices will also impact the value of our reserves. The process of estimating oil and natural gas reserves is complex and requires us to use a number of assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

Subject to the above, third-party estimates of our proved reserves as of December 31, 2013 was 5,234,550 BOE compared to 3,058,500 BOE as of December 31, 2012. This increase in proved developed reserves is primarily the result of the addition of proved undeveloped reserves in Oklahoma, an increase in proved undeveloped reserves in Louisiana, and an increase in proved developed reserves in Louisiana as a result of recompletion and workover activity.

We are dependent upon transportation and storage services provided by third parties.

We are dependent upon transportation services provided by barge operators and various interstate and intrastate pipeline companies for the delivery and sale of oil and gas production. The performance of transportation services by interstate pipelines and the rates charged for such services are subject to the jurisdiction of the Federal Energy Regulatory Commission or state regulatory agencies. An inability to obtain transportation services at competitive rates could hinder processing and marketing operations and/or affect our sales margins.

Competitive industry conditions may negatively affect our ability to conduct operations.

We operate in the highly competitive areas of oil and gas exploration, development, and production. We compete with other oil and gas companies for the purchase of leases, most of which have materially greater economic resources than we do. These leases include exploration prospects as well as properties with proved reserves. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel to properly evaluate seismic, geological and other information relating to a property;
- our ability to obtain pipe, drilling rigs and associated equipment and field personnel in a timely manner and at competitive prices;
- the location of, and our access to, pipelines and other facilities used to produce and transport oil and gas production;
- the standards we establish for the minimum projected return on an investment or our capital; and
- the availability of alternative fuel sources.

Our competitors include major integrated oil companies, independent energy companies, and affiliates of major interstate and intrastate pipelines and national and local gas gatherers, many of which possess greater financial, technological and other resources than we do.

Our decision to drill a prospect, whether developmental or exploratory, is subject to a number of factors and we may decide to alter our drilling schedule or not drill at all.

We describe our current properties and our plans to explore these properties in this report. Our proved properties are in various stages of evaluation and range from existing wells to be recompleted in other zones to drilling prospects which may require additional testing, data processing and interpretation. Whether we ultimately drill or continue to drill a prospect may depend on multiple factors, including, but not limited to, the following:

- acquisition and utilization of various evaluation technologies;
- material changes in oil or gas prices;
- the costs and availability of drilling rigs and equipment;
- the success or failure of wells drilled in comparable formations or which would use the same production facilities;
- availability and cost of capital;
- if warranted, our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks; and
- decisions of our joint working interest owners, if any.

We are constantly gathering data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all. You should understand that our plans regarding our prospects are subject to change.

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Weather, unexpected subsurface conditions, and other unforeseen hazards may adversely impact our ability to conduct business.

There are many operating hazards in exploring for and producing oil and gas, including:

- our drilling operations may encounter unexpected formations, pressures, lost circulation and/or other unforeseen conditions which could cause damage to equipment, personal injury or equipment failure;
- we may experience power outages, evacuation due to adverse weather conditions, labor disruptions, fire and/or equipment failures which could curtail or stop drilling or production; and
- we could experience blowouts, sour gas leakages, mechanical failures or damages to productive formations that may require a well to be re-drilled or other corrective action to be taken.

In addition, any of the foregoing may result in environmental damages for which we could be liable. We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

A shortage of drilling rigs and other equipment and geophysical service crews could hamper our ability to exploit any oil and gas resources we may acquire.

Competition for available drilling rigs and related services and equipment is intense. We may not be able to procure the necessary drilling rigs and related services and equipment, or the cost of such items may be prohibitive. Our ability to generate revenues from oil and gas production could be hampered as a result of this and our business could suffer.

Drilling wells could result in liabilities that could endanger our interests in our prospective properties and assets.

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, sour gas releases, fires and spills. The occurrence of any of these events could significantly reduce our future revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. We carry insurance with respect to these hazards as appropriate to our activities, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Decommissioning costs are unknown and may be substantial; unplanned costs could divert resources from other projects.

We are responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which we may use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “decommissioning.” We have a cash escrow account in place with the State of New York and a Letter of Credit in place with the State of Oklahoma for wells in those states. In addition, we have Site Specific Trust Accounts (“SSTA”) in place with the State of Louisiana to address these costs in our Louisiana fields. The SSTA’s are funded with a combination of cash and letters of credit drawn against our senior credit facility. The cash portion of the accounts was determined by management to be a reasonable estimate of the abandonment costs likely to be incurred in the two years subsequent to closing of the initial acquisition. If decommissioning is required before economic depletion of these properties or if the actual cost of decommissioning exceeds the value of the escrow account or the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our inability to obtain necessary facilities and equipment could hamper our operations.

Oil and natural gas exploration and development activities are dependent on the availability and cost of drilling and related equipment, transportation, power and technical support in the particular areas where these activities will be conducted. To the extent that we conduct our activities in remote areas or “in the water” environments, needed facilities may not be proximate to these areas which will increase our expenses. Demand for limited equipment and facilities or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. The quality and reliability of necessary facilities may also be unpredictable and we may be required to make efforts to standardize our facilities, which may entail unanticipated costs and delays. Shortages and/or the unavailability of necessary equipment or other facilities will impair our activities, either by delaying our activities, increasing our costs or both.

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Our ability to sell natural gas and/or receive market prices for natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

If our drilling programs that involve natural gas production are successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If that occurs, it will be necessary for new pipelines and gathering systems to be built. Capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas from our properties to interstate pipelines. In such event, we might have to shut in one or more of our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could reduce profitability, growth and the value of our business.

Oil and natural gas prices will continue to fluctuate in the future. Price fluctuations could have a significant impact upon our revenue, the return from our reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Although we have hedge positions in place for a significant portion of our oil and gas production, decreases in the prices of oil and natural gas could still have a material adverse effect on our consolidated financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

Our operations are subject to numerous federal, state and local laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require that we acquire permits before commencing drilling;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetland or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, such as dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for personal injury and cleanup costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from some or all of our properties in the event of significant environmental damage.

Factors beyond our control affect our ability to market production and our financial results.

The ability to market oil and gas produced from our wells depends upon numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and gas;

- the proximity of the gas production to gas pipelines;
- the availability of pipeline capacity;
- economic conditions experienced by commodity buyers;
- the demand for oil and gas by utilities and other end users;
- pipeline curtailments and/or delays;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

Additionally, world prices and markets for oil and gas are unpredictable, highly volatile, potentially subject to governmental fixing, pegging, controls, or any combination of these and other factors, and respond to changes in domestic, international, political, social, and economic environments. Also, due to worldwide economic uncertainty, the availability and cost of funds for production and other expenses have become increasingly difficult, if not impossible, to project. These changes and events may materially adversely affect our financial performance.

Because of these factors, we may be unable to market all of the oil or gas that we might produce. In addition, we may be unable to obtain favorable prices of the oil and gas that we might produce.

Our insurance may be inadequate to cover liabilities we may incur.

Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although we carry insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, we may choose not to obtain insurance to protect against specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to us. If we suffer a significant event or occurrence that is not fully insured, or if the insurer of such event is not solvent, we could be required to divert funds from capital investment or other uses towards covering our liability for such events.

Oil and gas operations are subject to comprehensive regulation which may cause substantial delays or require capital outlays in excess of those anticipated causing an adverse effect on our company.

Oil and gas operations are subject to federal, state, and local laws relating to the protection of the environment, including laws regulating the removal of natural resources from the ground and the discharge of materials into the environment. Oil and gas operations are also subject to federal, state, and local laws and regulations which seek to maintain health and safety standards by regulating the design and use of drilling methods and equipment. Various permits from government bodies are required for drilling and production operations to be conducted and no assurance can be given that such permits will be received. Environmental standards imposed by federal, provincial, or local authorities may be changed and any such changes may have material adverse effects on our activities. Moreover, compliance with such laws may cause substantial delays or require capital outlays in excess of those anticipated, thus causing an adverse effect on us. Additionally, we may be subject to liability for pollution or other environmental damages. We generally maintain insurance coverage customary to the industry; however, we are not fully insured against all possible environmental risks. To date we have not been required to spend any material amount on compliance with environmental regulations. However, we may be required to do so in the future and this may affect our ability to expand or maintain our operations.

Drilling activities are subject to certain environmental regulations which may prevent or delay the commencement or continuance of our operations.

In general, our drilling activities are subject to certain federal, state and local laws and regulations relating to environmental quality and pollution control. Such laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Compliance with these laws and regulations has not had a material effect on our consolidated results of operations or financial condition to date. Specifically, we are subject to legislation regarding emissions into the environment, water discharges and storage and disposition of hazardous wastes. In addition, legislation has been enacted which requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. However, such laws and regulations are frequently changed and we are unable to predict the ultimate cost of compliance. Generally, environmental requirements do not appear to affect us any differently or to any greater or lesser extent than other companies in the industry.

We believe that our operations comply, in all material respects, with all applicable environmental regulations.

Risks Relating to Our Common Stock:

There has been a limited trading market for our common stock.

From time to time, the lack of an active market may impair your ability to sell your shares at the time you wish to sell them or at a price that you consider reasonable. The lack of an active market may also reduce the fair market value of your shares. An inactive market could also impair our ability to raise capital by selling shares of capital stock and may impair our ability to acquire additional properties or other companies by using common stock as consideration.

You may have difficulty trading and obtaining quotations for our common stock.

Our common stock is considered to be a thinly traded stock and the bid and asked prices may fluctuate widely. As a result, investors may find it difficult to dispose of or to obtain accurate quotations of the price of our securities. This severely limits the liquidity of the common stock and could reduce the market price of our common stock and hamper our ability to raise additional capital.

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Our common stock is not currently traded at high volume, and you may be unable to sell at or near ask prices or at all if you need to sell or liquidate a substantial number of shares at one time.

Our common stock is currently traded with relatively low volume, meaning that the number of persons interested in purchasing our common stock at or near bid prices at any given time may be relatively small. This situation is attributable to a number of factors, including the fact that we are a small company which is still relatively unknown to stock analysts, stock brokers, institutional investors and others in the investment community that generate or influence sales volume, and that even if we came to the attention of such persons, they tend to be risk-averse and would be reluctant to follow an unproven company such as ours or purchase or recommend the purchase of our shares until such time as we became more seasoned and viable. As a consequence, there may be periods when trading activity in our shares is minimal as compared to a seasoned issuer which has a large and steady volume of trading activity that will generally support continuous sales without an adverse effect on share price. We cannot give you any assurance that a broader or more active public trading market for our common stock will develop or be sustained, or that trading levels will be sustained.

Shareholders should be aware that, according to Commission Release No. 34-29093, the market for “penny stocks” has suffered in recent years from patterns of fraud and abuse. Such patterns include (1) control of the market for the security by one or a few broker-dealers that are often related to the promoter or issuer; (2) manipulation of prices through prearranged matching of purchases and sales and false and misleading press releases; (3) boiler room practices involving high-pressure sales tactics and unrealistic price projections by inexperienced sales persons; (4) excessive and undisclosed bid-ask differential and markups by selling broker-dealers; and (5) the wholesale dumping of the same securities by promoters and broker-dealers after prices have been manipulated to a desired level, along with the resulting inevitable collapse of those prices and with consequent investor losses. Our management is aware of the abuses that have occurred historically in the penny stock market. Although we do not expect to be in a position to dictate the behavior of the market or of broker-dealers who participate in the market, management will strive within the confines of practical limitations to prevent the described patterns from being established with respect to our securities. The occurrence of these patterns or practices could increase the future volatility of our share price.

The market price of our common stock is likely to be highly volatile and subject to wide fluctuations.

The market price of our Common Stock is likely to be highly volatile and could be subject to wide fluctuations in response to a number of factors, some of which are beyond our control, including:

- dilution caused by our issuance of additional shares of Common Stock and other forms of equity securities in connection with future capital financings to fund our operations and growth, to attract and retain valuable personnel and in connection with future strategic partnerships with other companies;
- quarterly variations in our revenues and operating expenses;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;
- changes in analysts’ estimates affecting our company, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- additions and departures of key personnel;

- fluctuations in interest rates and the availability of capital in the capital markets; and
- the sale of large blocks of our common stock.

These and other factors are largely beyond our control, and the impact of these risks, singly or in the aggregate, may result in material adverse changes to the market price of our Common Stock and/or our results of operations and financial condition.

We have not paid dividends in the past and do not expect to pay dividends in the future. Any return on investment may be limited to the value of our common stock.

We have never paid cash dividends on our common stock and do not anticipate paying cash dividends in the foreseeable future. The payment of dividends on our common stock will depend on earnings, financial condition and other business and economic factors affecting it at such time as the Board of Directors may consider relevant.

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You may experience dilution of your ownership interests because of the future issuance of additional shares of our common stock.

In the future, we may issue additional authorized but previously unissued equity securities resulting in the dilution of the ownership interests of our present and future stockholders. We are currently authorized to issue an aggregate of 101,000,000 shares of capital stock comprising 100,000,000 shares of common stock and 1,000,000 shares of preferred stock with preferences and rights to be determined by our Board of Directors. As of March 31, 2014, there were 56,030,473 shares of our common stock and no shares of our preferred stock outstanding. There are 5,000,000 shares of our common stock reserved for issuance under our 2012 Long-Term Incentive Plan. Shares issued and outstanding do not include shares of our common stock issuable upon the exercise of outstanding options and warrants.

Any future issuance of our equity or equity-backed securities may dilute then-current stockholders' ownership percentages and could also result in a decrease in the fair market value of our equity securities, because our assets would be owned by a larger pool of outstanding equity. As described above, we may need to raise additional capital through public or private offerings of our common or preferred stock or other securities that are convertible into or exercisable for our common or preferred stock. We may also issue such securities in connection with hiring or retaining employees and consultants (including stock options issued under our equity incentive plans), as payment to providers of goods and services, in connection with future acquisitions or for other business purposes. Our Board of Directors may at any time authorize the issuance of additional common or preferred stock without common stockholder approval, subject only to the total number of authorized common and preferred shares set forth in our certificate of incorporation. The terms of equity securities issued by us in future transactions may be more favorable to new investors, and may include dividend and/or liquidation preferences, superior voting rights and the issuance of warrants or other derivative securities, which may have a further dilutive effect. Also, the future issuance of any such additional shares of common or preferred stock or other securities may create downward pressure on the trading price of the common stock. There can be no assurance that any such future issuances will not be at a price (or exercise prices) below the price at which shares of the common stock are then traded.

We may obtain additional capital through the issuance of preferred stock, which may limit your rights as a holder of our Common Stock.

Without any stockholder vote or action, our Board of Directors may designate and approve for issuance shares of our preferred stock. The terms of any preferred stock may include priority claims to assets and dividends and special voting rights which could limit the rights of the holders of our common stock. The designation and issuance of preferred stock favorable to current management or stockholders could make any possible takeover of the Company or the removal of our management more difficult.

Legislative actions, higher insurance costs and potential new accounting pronouncements may impact our future financial position and results of operations.

There have been regulatory changes, including the Sarbanes-Oxley Act of 2002, and there may potentially be new accounting pronouncements or additional regulatory rulings that will have an impact on our future financial position and results of operations. The Sarbanes-Oxley Act of 2002 and other rule changes as well as proposed legislative initiatives following the Enron bankruptcy are likely to increase general and administrative costs and expenses. In addition, insurers are likely to increase premiums as a result of high claims rates over the past several years, which we expect will increase our premiums for insurance policies. Further, there could be changes in certain accounting rules. These and other potential changes could materially increase the expenses we report under generally accepted accounting principles, and adversely affect our operating results.

If securities analysts do not initiate coverage or continue to cover our common stock or publish unfavorable research or reports about our business, this may have a negative impact on the market price of our common stock.

The trading market for our common stock may be affected by, among other things, the research and reports that securities analysts publish about our business and our company. We do not have any control over these analysts. There is no guarantee that securities analysts will cover our common stock. If securities analysts do not cover our common stock, the lack of research coverage may adversely affect its market price. If we are covered by securities analysts, and our stock is the subject of an unfavorable report, our stock price and trading volume would likely decline. If one or more of these analysts ceases to cover our company or fails to publish regular reports on us, we could lose visibility in the financial markets, which could cause our stock price or trading volume to decline.

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Efforts to comply with recently enacted changes in securities laws and regulations will increase our costs and require additional management resources.

As directed by Section 404 of the Sarbanes-Oxley Act of 2002, the SEC adopted rules requiring public companies to include a report of management on their internal controls over financial reporting in their annual reports on Form 10-K. In addition, in the event we are no longer a smaller reporting company, the independent registered public accounting firm auditing our financial statements would be required to attest to the effectiveness of our internal controls over financial reporting. Such attestation requirement by our independent registered public accounting firm would not be applicable to us until the report for the year ended December 31, 2014 at the earliest, if at all.

Our common stock is subject to the "penny stock" rules of the SEC and the trading market in our securities is limited, which makes transactions in our stock cumbersome and may reduce the value of an investment in our stock.

The SEC has adopted Rule 15g-9 which establishes the definition of a "penny stock," for the purposes relevant to us, as any equity security that has a market price of less than $5.00 per share or with an exercise price of less than $5.00 per share, subject to certain exceptions. For any transaction involving a penny stock, unless exempt, the rules require:

- that a broker or dealer approve a person's account for transactions in penny stocks; and
- the broker or dealer receive from the investor a written agreement to the transaction, setting forth the identity and quantity of the penny stock to be purchased.

In order to approve a person's account for transactions in penny stocks, the broker or dealer must:

- obtain financial information and investment experience objectives of the person; and
- make a reasonable determination that the transactions in penny stocks are suitable for that person and the person has sufficient knowledge and experience in financial matters to be capable of evaluating the risks of transactions in penny stocks.

The broker or dealer must also deliver, prior to any transaction in a penny stock, a disclosure schedule prescribed by the SEC relating to the penny stock market, which, in highlight form:

- sets forth the basis on which the broker or dealer made the suitability determination; and
- that the broker or dealer received a signed, written agreement from the investor prior to the transaction.

Generally, brokers may be less willing to execute transactions in securities subject to the "penny stock" rules. This may make it more difficult for investors to dispose of our common stock and cause a decline in the market value of our stock.

Disclosure also has to be made about the risks of investing in penny stocks in both public offerings and in secondary trading and about the commissions payable to both the broker-dealer and the registered representative, current quotations for the securities and the rights and remedies available to an investor in cases of fraud in penny stock transactions. Finally, monthly statements have to be sent disclosing recent price information for the penny stock held in the account and information on the limited market in penny stocks.

FINRA sales practice requirements may also limit a shareholder’s ability to buy and sell our stock.

In addition to the “penny stock” rules described above, FINRA has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer’s financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. The FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit your ability to buy and sell our stock and have an adverse effect on the market for our shares.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The information set forth above under "Business" relating to our oil and gas properties is incorporated herein by reference.

Our corporate offices are currently located in Spring Valley Center, a six-story office complex at 5220 Spring Valley Road, Dallas, Texas 75254. The current lease for our corporate office space (Suite 615) expires on July 31, 2015. The existing office space covers 5,229 square feet with a monthly rent of $7,390. Of that total, 767 square feet are currently subleased for a monthly rent of $1,085.

In addition, we have 7,832 square feet of office space in a single story building at 71683 Riverside Drive, Covington, LA 70433 with a monthly rent of $6,851. That lease expires March 31, 2014. TNR's operational team is at that location. That lease was renewed effective April 1, 2014, for a period of twenty-four months at a monthly rental of $7,832. The lease renewal contains an option to renew the lease after the expiration of the initial twenty-four month term at a monthly rental of $8,485. We believe that there is ample space to accommodate additional growth in the foreseeable future.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may become involved in various lawsuits and legal proceedings which arise in the ordinary course of business. Litigation is subject to inherent uncertainties, and an adverse result in these or other matters that may arise from time to time that may harm business. To the best of our knowledge, there is currently no pending legal proceeding and, as far as we are aware, no governmental authority is contemplating any proceeding to which we are a party or to which any of our properties is subject.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Price Range of Common Stock

Our common stock is currently traded on the OTC Bulletin Board under the symbol "AOIL." Prior to May 14, 2012, our common stock traded on the OTC Bulletin Board under the symbol "NDBE." The following table sets forth the high and low closing prices per share of common stock for the quarters indicated.

	Fiscal Year 2012	
	High	Low
First Quarter	$ 1.80	$ 0.65
Second Quarter	$ 1.82	$ 1.31
Third Quarter	$ 1.50	$ 1.01
Fourth Quarter	$ 1.25	$ 0.41

	Fiscal Year 2013	
	High	Low
First Quarter	$ 0.84	$ 0.50
Second Quarter	$ 0.53	$ 0.27
Third Quarter	$ 0.35	$ 0.25
Fourth Quarter	$ 0.27	$ 0.16

On March 28, 2014, the closing sale price of our common stock was $0.225 per share and there were approximately 194 holders of record of our common stock.

Dividends

We have never paid any cash dividends on our capital stock and do not anticipate paying any cash dividends on our common stock in the foreseeable future. Also, the terms of our convertible promissory notes restrict our ability to pay dividends. We intend to retain future earnings to fund ongoing operations and future capital requirements of our business. Any future determination to pay cash dividends will be at the discretion of the Board of Directors and will be dependent upon our financial condition, results of operations, capital requirements and such other factors as the Board of Directors deems relevant.

Securities Authorized for Issuance Under Equity Compensation Plans

On September 30, 2002, the stockholders of the Company approved its 2002 Incentive Stock Plan (the "2002 Plan"), which had 4,000,000 shares reserved for issuance thereunder. The 2002 Stock Plan expired in September 2012. In anticipation of its expiration, by way of Unanimous Written Consent dated April 27, 2012, the Board of Directors approved the terms and provisions of the 2012 Long-Term Incentive Plan ("2012 Incentive Plan"). The 2012 Incentive Plan was approved by shareholders owning the majority of the Company's shares of common stock and became effective on May 1, 2012, The 2012 Incentive Plan allows for awards of up to an aggregate of 5,000,000 shares of our common stock, subject to adjustment under certain circumstances. The 2012 Incentive Plan provided shares available for options granted to employees, directors, and others. Stock options granted under the 2012 Incentive Plan generally vest over one to five years or as otherwise determined by the Board of Directors or committee of the Board of

Directors. Options to purchase shares of common stock expire no later than ten years after the date of grant. As of March 31, 2014, we have outstanding option awards under the 2012 Incentive Plan of 2,794,000, of which vested options are currently exercisable for an aggregate of 2,517,000, shares of our common stock, and our Board of Directors has granted awards of restricted stock with respect to an aggregate of 555,200 shares. We have not maintained any other equity compensation plans since our inception.

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The following table provides information as of December 31, 2013, with respect to the shares of common stock that may be issued under our existing equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (2) (c)
Equity compensation plans approved by security holders (1)	2,794,000	$	0.41	1,650,800
Equity compensation plans not approved by security holders	—		—	—
Total	2,794,000	$	0.41	1,650,800

(1) 2012 Long-Term Incentive Plan
(2) Net of 555,200 shares awarded as restricted stock grants.

Stock Transfer Agent

Our Stock Transfer Agent is Broadridge Corporate Issuer Solutions, Inc., located at 51 Mercedes Way, Edgewood, NY 11717.

Sales of Unregistered Equity Securities

Except as previously disclosed in Quarterly Reports on Form 10-Q or Current Reports on Form 8-K that we have filed, or otherwise set forth below, during the period covered by this Report we have not sold any of our equity securities that were not registered under the Securities Act of 1933, as amended (the "Securities Act").

ITEM 6. SELECTED FINANCIAL DATA

Not required under for smaller reporting companies.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements that involve risks, uncertainties and assumptions. See "Note Regarding Forward-Looking Statements." Our actual results could differ materially from those anticipated in the forward-looking statements as a result of certain factors discussed in "Risk Factors" and elsewhere in this Annual Report on Form 10-K.

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. The discussion should be read in conjunction with our audited financial statements and related notes and the other financial information included elsewhere in this report.

Adjusted EBITDA as a Non-GAAP Performance Measure

In evaluating our business, management believes earnings before interest, amortization of financing costs, taxes, depreciation, depletion, amortization and accretion of abandonment liabilities, unrealized gains and losses on financial instruments, gains and losses on sales of assets and asset retirement obligations, 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.

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The following is a reconciliation of our net income in accordance with GAAP to our Adjusted EBITDA for the years ended December 31, 2013 and 2012:

	2013	2012
Net loss	$ (11,369,765)	$ (140,711)
Add:		
Interest (income) expense, net	795,360	495,036
Amortization of deferred financing costs	56,292	44,213
Income tax (benefit)/expense	(1,766,140)	489,265
Depreciation, depletion, accretion and impairment	1,231,340	1,832,537
Dry hole expense	2,591,770	--
Impairment of goodwill	8,536,758	--
(Gain) loss on settlement of asset retirement obligation	(3,428)	116,394
Loss on change in commodity derivative instruments	251,876	912,963
Loss on change in convertible debt derivative	--	534,989
Loss on modification of offering terms	65,749	--
Loss on sales of oil and gas properties	86,116	--
Share-based compensation	737,822	349,407
Adjusted EBITDA	$ 1,213,750	$ 4,634,093

Recent Developments

As part of the execution of our business strategy discussed in Item I, above, we have recently taken the following steps:

- F&M Credit Facility - 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 had an initial maturity date of July 22, 2013. The interest rate is the F&M Bank Base Rate plus 1% subject to a floor of 5.75%. At present, interest is accruing at 5.75% and is paid monthly. A 2.00% annual fee is applicable to letters of credit drawn under the Credit Facility. The Credit Facility provided financing for the acquisition of TNR, working capital for field enhancements, and general corporate purposes. The Credit Facility was 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.
- In April 2012, F&M Bank performed the first scheduled redetermination of MEI's credit facility and increased MEI's borrowing base from $10,500,000 to $13,500,000. The redetermination also lifted MEI's obligation to make the $150,000 monthly payments required prior to the redetermination.
- In September 2012, F&M Bank performed the second scheduled redetermination of the Credit Facility, increased MEI's borrowing base from $13,500,000 to $14,500,000, and extended the maturity date to July 22, 2014.

- In December 2012, MEI drew $4,000,000 against the Credit Facility to fund the drilling of the Thomas #6H well in Oklahoma.
- In the third quarter of 2012, MEI made the decision to insource our oil and gas accounting operations and implemented an enterprise resource planning (ERP) system.
- On November 14, 2012, Mesa executed an Asset Purchase Agreement and Plan of Reorganization (the “Acquisition Agreement”) with us, which closed on March 28, 2013 and pursuant to which we acquired the assets of Mesa.
- On December 20, 2013, we entered into a Unit Purchase Agreement with Gulfstar Resources, LLC, designed to provide additional development capital for our Louisiana properties as well as to allow us to reallocate a portion of our asset base to other operating areas. Under the terms of this agreement, we completed a first tranche closing in which we received $6,250,000 in exchange for a 34.375% interest in TNRH.
- On March 14, 2014, Armada Midcontinent, LLC, (f/k/a MMC Resources, LLC) a wholly owned subsidiary of MEI, entered into a purchase and sale agreement with Piqua Petro, Inc., pursuant to which Armada Midcontinent, LLC agreed to purchase from Piqua Petro its interests in six oil and gas leases covering approximately 1,040 acres in Woodson County, Kansas.

The Mesa Acquisition Closing

On March 28, 2013, we closed (the “Closing”) the purchase from Mesa of 100% of the issued and outstanding shares of MEI, constituting substantially all of Mesa’s assets. MEI is now a wholly owned subsidiary of Armada. In connection with the consummation of the Mesa Acquisition, and immediately prior to the Closing, Mesa and MEI entered into an Assignment and Assumption Agreement (the “Assignment and Assumption Agreement”), as contemplated by the Acquisition Agreement, pursuant to which Mesa assigned to MEI and MEI assumed all of Mesa’s assets and liabilities.

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As consideration for the Mesa Acquisition, we received and distributed to our stockholders 0.40 shares of Armada common stock (the "Acquisition Consideration") for each share of our common stock that a stockholder of ours owned as of the close of business on March 27, 2013, the business day immediately preceding the closing date of the Mesa Acquisition. As of the Closing, and as a result of the Mesa Acquisition, each outstanding share of Mesa common stock was converted into the Acquisition Consideration. In accordance with the Acquisition Agreement, after the distribution of the Acquisition Consideration, Mesa wound up and dissolved and ceased its corporate existence.

Results of Operations for the Fiscal Year Ended December 31, 2013 Compared to Fiscal Year Ended December 31, 2012

Revenue

The following table summarizes our revenues from commodity sales during the years ended December 31, 2013, and 2012.

	Years Ended December 31, 2013	Years Ended December 31, 2012	Difference	Percentage Change
Revenues				
Oil	$ 10,321,582	$ 12,219,706	$ (1,898,124)	-15.5%
Natural gas	1,777,673	2,213,296	(435,623)	-19.7%
Natural gas liquids	186,567	119,086	67,481	56.7%
Total	$ 12,285,822	$ 14,552,088	$ (2,266,266)	-15.6%
Sales volumes				
Oil (Bbls)	100,126	112,399	(12,273)	-10.9%
Natural gas (MCF)	456,113	756,198	(300,085)	-39.7%
Natural gas liquids (Bbl)	4,529	2,984	1,545	51.8%
Total BOE	176,900	238,929	(62,029)	-26.0%
Total BOE/day	485	653		
Average prices				
Oil (per Bbl)	$ 103.09	$ 108.72	$ (5.63)	-5.3%
Natural gas (per MCF)	3.90	2.93	0.97	32.7%
Natural gas liquids (per Bbl)	41.20	39.91	1.29	3.2%
Total per BOE	$ 69.45	$ 60.91	$ 8.54	14.0%

Revenues from commodity sales decreased during the year ended December 31, 2013 over the year ended December 31, 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 year ended December, 2013, we had $150,388 of revenue from lease fuel; marketing, compression, and transportation fees; and production handling fees for a third party. During the year ended December 31, 2012, we had $313,081 of such income. The decrease over 2012 is attributable to lower sales volumes with which some of the fees are associated as well as a decrease in COPAS overhead and compression fees.

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Operating Expenses

Operating expenses for the years ended December 31, 2013 and 2012 are set forth in the table below.

	Years Ended December 31, 2013	2012	Difference	Percentage Change
Costs and Expenses				
Lease operating expense (1)	$ 6,006,287	$ 5,138,278	$ 868,009	16.4%
Production and ad valorem taxes (2)	1,464,680	1,924,333	(459,653)	-23.0%
Environmental remediation expense	—	244,237	(244,237)	-100.0%
Exploration expense (3)	284,275	115,276	168,999	146.6%
Dry hole expense (4)	2,591,770	—	2,591,770	N/A
Depletion, depreciation, amortization, and impairment expense (5)	1,231,340	1,832,537	(601,197)	-32.8%
Loss on sale of oil and gas properties (6)	86,116	—	86,116	N/A
(Gain) loss on settlement of asset retirement obligation (7)	(3,428)	116,394	(119,822)	-102.9%
Impairment of goodwill (8)	8,536,758	—	8,536,758	N/A
General and administrative expense (9)	4,469,260	3,636,010	833,250	22.9%
Total operating expenses	$ 24,667,058	$ 13,007,066	$ 11,659,992	89.6%

(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 reduction in asset retirement costs for wells after revaluation of asset retirement obligations.
(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, and a 2013 gain of $2,100 on the retirement of the asset retirement obligations upon the sale of our Archer and Young County, Texas, properties, as compared to a 2012 loss of $116,394 for the plugging and abandonment of two wells.
(8) Impairment of goodwill attributable to acquisition of Armada due to revision of tax basis in assets acquired.
(9) 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 Assignment and Assumption Agreement and the Gulfstar Transaction.

Operating expenses expressed in BOE for the years ended December 31, 2013 and 2012 are set forth in the table below:

	Years Ended December 31, 2013	2012	Difference	Percentage Change
Costs and Expenses				

Lease operating expense	$ 33.88	$ 21.51	$ 12.29	56.9%
Production and ad valorem taxes	8.26	7.96	0.30	3.8%
Environmental remediation expense	—	1.02	(1.02)	-100.0
Exploration expense	1.60	0.48	1.12	232.4%
Dry hole expense	14.62	—	14.62	N/A
Depletion, depreciation, amortization, and impairment expense	6.95	7.67	(0.72)	9.4%
Loss on sale of oil and gas properties	0.49	—	0.49	N/A
(Gain) loss on settlement of asset retirement obligation	(0.02)	0.49	(0.51)	-104.0%
Impairment of goodwill	48.16	—	48.16	N/A
General and administrative expense	25.21	15.22	8.99	59.1%
Total operating expenses	$ 90.99	$ 54.44	$ 35.55	65.3%

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Operating (income) loss. As a result of the above described revenues and expenses, we incurred an operating loss of $12,230,848 during the year ended December 31, 2013 as compared to operating income of $1,858,104 during the year ended December 31, 2012.

Interest expense. Interest expense increased to $822,335 for the year ended December 31, 2013, from $503,638 for the year ended December 31, 2102. $156,011 of this increase was primarily attributable to amortization of discount on notes payable, as well as $47,458 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 increased by $4 million in December 2012, and the year ended December 31, 2013, saw a full year of interest expense associated with the increased borrowing under the credit facility, net of repayments of principal.

Unrealized gain (loss) on changes in derivative value. The unrealized loss on change in derivatives – commodity contracts for the year ended December, 2013, was $251,876. Unrealized loss on change in derivatives – commodity contracts for the year ended December 31, 2012, was $912,963. The unrealized losses in years ended December 31, 2013 and 2012 were the result of the changes in the fair 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 $534,989 was incurred during the year ended December 31, 2012; but no convertible debt existed during the year ended December 31, 2013.

Realized gain on changes in derivatives – commodity contracts. Cash settlements from hedging our sales of oil and gas production were $216,000 in the year ended December 31, 2013 as compared to $440,699 in the year ended December 31, 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 year ended December 31, 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 year ended December 31, 2012.

Income tax benefit (expense). State and federal income tax benefit for the year ended December 31, 2013 was $1,766,140 compared to income tax expense of $489,265 in the year ended December 31, 2012. The income tax benefit in the year ended December 31, 2013 is primarily attributable to our net loss. The income tax benefit for the year ended December 31, 2012, is attributable to net income during that period.

Net loss. Due to the reasons set forth above, our net loss after income tax benefit for the year ended December 31, 2013 was $11,369,765 ($0.22 per basic and diluted common share). Our net loss after income tax expense for the year ended December 31, 2012 was $140,711 ($0.00 per basic and diluted common share).

Liquidity and Capital Resources

Overview

As of December 31, 2013, we had a working capital deficit of $2,310,297. As of December 31, 2012, we had working capital of $5,649,632. The decrease in the working capital was attributable to:

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The reclassification of our credit facility with F&M Bank and other notes payable, totaling $8,659,500, from noncurrent to current

Our current assets increased by $948,980 during the year ended December 31, 2013 primarily due to increases in cash, deferred tax asset, and prepaid expenses net of decreases in accounts receivable and the derivative asset associated with or commodity contracts.

As of December 31, 2013, the outstanding balance of principal and accrued interest on debt was $8,913,177, a net decrease of $437,875 from the outstanding balance of $9,351,052 as of December 31, 2012. This net decrease was primarily due to repayments of principal on our credit facility with F&M Bank net of increases in debt associated with notes issued in conjunction with a private placement commenced prior to the Acquisition.

Our December 31, 2013, reserve report based on the SEC pricing case makes various assumptions regarding the pace of development of our proved undeveloped reserves. In order to develop these reserves on the schedule assumed in the reserve report, the capital expenditure requirement for 2014 would be $11,270,990, with 2015 and 2016 being $21,300,000 and $3,600,000, respectively. Based on the parameters and assumptions contained in the reserve report, we expect those funds to come from an equity injection as a result of the Gulfstar Transaction as well as from cash flow generated from operations. It should be noted, however, that the Company's obligations related to funding the capital expenditures outlined in the reserve report are likely to be substantially reduced as a result of the Gulfstar Transaction.

There are multiple factors that can affect these estimates including changes in commodity prices, adverse weather conditions and unforeseen events, both inside and outside of our business. In the event that unforeseen circumstances reduce our cash flow and create a shortfall in the capital expenditure budget, we have a number of other potential sources of funds to support the development effort including:

- Existing cash reserves of approximately $1 million;
- Additional debt financing; and
- Additional equity offerings.

If, however, cash flow plus the additional sources outlined above are not sufficient to support our portion of the capital expenditure budget outlined in the reserve report, our ability to execute our plan of operations could be negatively impacted and drilling activity could be reduced.

Cash and Accounts Receivable

At December 31, 2013, we had cash in banks of $7,095,972, compared to $5,884,649 at December 31, 2012. The $1,211,323 increase in cash was due primarily to the funding of Tranche A associated with the Unit Purchase Agreement entered into between the Company and Gulfstar Resources, LLC.

Liabilities

Accounts payable and accrued expenses increased by $91,740 to $2,226,052 at December 31, 2013, from $2,134,312 at December 31, 2012. The increase was primarily attributable to an $83,780 increase in the December 31, 2013, revenue payable balance.

Cash Flows

For the year ended December 31, 2013, the net cash provided by operating activities of $483,676, as compared to cash provided by operating activities of $3,123,917 in 2012.

For the year ended December 31, 2013, net cash used in investing activities was $2,855,088 as compared to cash used for investing activities of $3,944,237 in 2012. Cash used comprised primarily additional capital expenses associated with our Louisiana properties.

For the year ended December 31, 2013, net cash provided by financing activities was $3,583,235 comprising primarily net cash received of $5,366,188 from Gulfstar Resources, LLC as funding for Tranche A of a three part funding program from Gulfstar pursuant to the Unit Purchase Agreement between the Company and Gulfstar offset by $2,583,224 in repayments of debt, most significantly repayments of the balance of our credit facility with F&M Bank, net of proceeds received from our private placement after the Acquisition. During the year ended December 31, 2012, cash provided by financing activities was $3,522,577 comprising, primarily a $4,000,000 draw against our Credit

Facility to finance our Oklahoma drilling activity, net of retirements of notes associated with our Lake Hermitage camp and crew boat.

Off-Balance Sheet Arrangements

We do not have any 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.

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Critical Accounting Policies and Estimates

Our discussion of our financial condition and results of operations is based on the information reported in our financial statements. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies are described in Note 1 – ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES to our audited consolidated financial statements and notes thereto included in this Annual Report. We have outlined below certain of these policies that have particular importance to the reporting of our financial condition and results of operations and that require the application of significant judgment by our management.

Key Definitions

Proved reserves, as defined by the SEC, are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Valuations include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Prices do not include the effect of derivative instruments, if any, entered into by us.

Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods. Additional oil and gas volumes expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery would be included as proved developed reserves only after testing of a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves are those reserves that are expected to be recovered from new wells on non-drilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on non-drilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other non-drilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

Estimation of Reserves

Volumes of reserves are estimates that, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. There are numerous uncertainties in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. Natural gas and oil reserve engineering must be recognized as a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. Estimates of independent engineers that we use may differ from those of other engineers. The accuracy of any reserve estimate is a function of the quantity and quality of available data and of engineering and geological interpretation and judgment. Accordingly, future estimates are subject to change as additional information becomes available.

The most critical estimate we make is the engineering estimate of proved oil and gas reserves. This estimate affects the application of the successful efforts method of accounting, the calculation of depreciation, depletion and amortization of oil and gas properties and the estimate of any impairment of our oil and gas properties. It also affects the estimated lives used to determine asset retirement obligations. In addition, the estimates of proved oil and gas reserves are the basis for the annual year end disclosure of the related standardized measure of discounted future net cash flows.

Revenue Recognition

Revenues from the sale of crude oil and natural gas are recorded in the month the product is delivered to the purchaser at a fixed or determinable price, title transfers to the purchaser, and collectability is reasonably assured and evidenced by a contract. The Company generally receives payment from one to three months after the sale has occurred. Each month the Company estimates the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenues and actual amounts are recorded in the month payment is received and are reflected in the Company's Consolidated Statements of Operations as Revenue. These variances have historically not been material. The Company has no material imbalances resulting from natural gas sales, but if it did, it would use the sales method of accounting for natural gas imbalances. As a producer, the Company would adjust its reserves for gas imbalances. As a working interest owner, the Company would recognize an overproduced position as a liability on its balance sheet and an underproduced position as a receivable, to the extent collectible, from an overproduced owner.

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Successful Efforts Accounting

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under the successful efforts method, costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred. The Company evaluates its proved oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset's carrying value may not be recoverable. The Company follows Accounting Standards Codification ASC 360 - Property, Plant, and Equipment, for these evaluations. Unamortized capital costs are reduced to fair value if the undiscounted future net cash flows from our interest in the property's estimated proved reserves are less than the asset's net book value.

Impairment of Properties

We review our proved properties for potential impairment at the field level when management determines that events or circumstances indicate that the recorded carrying value of any of the properties may not be recoverable. Such events include a projection of future natural gas and oil reserves that will be produced from a well, the timing of this future production, future costs to produce the natural gas and oil, and future inflation levels. If the carrying amount of an asset exceeds the sum of the discounted estimated future net cash flows, we recognize impairment expense equal to the difference between the carrying value and the fair market value of the asset, which is estimated to be the expected discounted value of future net cash flows from reserves, without the application of any estimate of risk. We cannot predict the amount of impairment charges that may be recorded in the future. Unproved leasehold costs are reviewed periodically and impairment is recognized to the extent, if any, that the cost of the property has been impaired. We follow the Accounting Standards Codification ASC 360 Property, Plant, and Equipment, for these evaluations. Unamortized capital costs are reduced to fair value if the undiscounted future net cash flows from our interest in the property's estimated proved reserves are less than the asset's net book value.

Proved Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States of America and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the impairment. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. We engage independent reserve engineers to estimate our proved reserves.

Share-Based Compensation

Compensation expense has been recorded for grants of restricted common stock and options based on the fair value of the common stock on the measurement date. We estimate the fair value of each stock option award at the grant date by using the Black-Scholes option pricing model. FASB ASC Topic No. 718-10 establishes standards for transactions in which an entity obtains employee services in share-based payment transactions. The guidance requires that the fair value of such equity instruments be recognized as expense in the historical financial statements as services are performed. Standards of accounting for transactions in which an entity exchanges its equity instruments for goods and services by a consultant or contractor are further governed by FASB ASC Topic No. 505-50 by which the grant is measured at the fair value of the stock exchanged and the associated expense is recorded according to the category of the goods received or service rendered.

Derivative Valuation

We estimate the fair value of financial assets and liabilities based on a three-level valuation hierarchy for disclosures of fair value measurement and enhance disclosure requirements for fair value measures.

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The three levels are defined as follows:

- Level 1 - inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

All derivative instruments are recorded on the balance sheet at their fair value. Changes in the fair value of each derivative are recorded each period in current period earnings.

We do not apply hedge accounting, as our hedging program is designed only to comply with covenants underlying our credit facility with F&M Bank and not as a formal risk management program, and we do not monitor the effectiveness of the hedge. Realized gains and losses (i.e., cash settlements) are reported in the Statement of Operations. Similarly, changes in the fair value of unsettled derivative instruments are recorded as unrealized gains or losses in the Statement of Operations.

New Accounting Pronouncements

We do not expect the adoption of any recently issued accounting pronouncements to have a significant impact on our results of operations, financial position or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not required for smaller reporting companies.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our audited consolidated financial statements as of, and for the years ended, December 31, 2013 and 2012 are included beginning on Page F-1 immediately following the signature page to this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

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ITEM 9A. 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 (“Exchange Act”) as of December 31, 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 December 31, 2013, our disclosure controls and procedures are not effective and are not designed at a reasonable 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 December 31, 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 have engaged additional employees and 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.

In January 2013, we completed the implementation of our enterprise resource planning (ERP) system and “went live” with accounting processes. Throughout 2013, we undertook the implementation of the land management features of the new system.

Other than these events, there were no changes in our internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Rule 13a-15 or Rule 15d-15 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(c) Management’s report on internal control over financial reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was not effective as of December 31, 2013 for the reason indicated above. The effectiveness of our internal control over financial reporting as of December 31, 2013 has not been audited by GBH CPAs, PC, our independent registered public accounting firm. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act, smaller reporting companies are exempt from the requirement that management's report be subject to an audit by an independent registered public accounting firm.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Executive Officers and Directors

The names of our directors and executive officers and their ages, titles, and biographies as of March 27, 2014, unless otherwise indicated, are set forth below:

Name	Age	Title	Date First Appointed
Randy M. Griffin	60	Chairman of the Board and Chief Executive Officer	August 31, 2009
Rachel L. Dillard	62	Chief Financial Officer	September 19, 2011
James J. Cerna, Jr.	45	President and Director	January 5, 2010
J. Clint Unruh	35	Executive Vice President – Land	April 4, 2013
Ray L. Unruh	67	Secretary and Director	August 31, 2009
Kenneth T. Hern	76	Director	January 27, 2010
Fred B. Zaziski	61	Director	January 5, 2010
Marceau Schlumberger	42	Director	March 28, 2013
Eric Wold	41	Director	March 28, 2013

Directors are elected to serve until the next annual meeting of stockholders and until their successors are elected and qualified. Executive officers are appointed by the Board of Directors and serve at its pleasure.

Certain biographical information for each of our executive officers and directors is set forth below.

Randy M. Griffin served as Chairman of the Board of Directors and Chief Executive Officer of Mesa from its founding in April of 2003 until the closing of the Mesa Acquisition in March of 2013, at which time he became Chairman of the Board of Directors and Chief Executive Officer of Armada. Mr. Griffin's responsibilities include oversight of the business and administrative activities of the company, direction of the ongoing effort to identify potential acquisitions and evaluation of potential financing strategies.

From March 2001 until March 2003, Mr. Griffin was associated with a Dallas-based group of companies engaged in the development of a horizontal natural gas drilling project in Shelby County, Texas. His responsibilities included pipeline development, land management and lease acquisition. During that period, he was responsible for the negotiation and closing of the sale of that company's natural gas production and undeveloped property in Shelby County, a divestiture valued at just under $30,000,000. In addition, he negotiated the acquisition of an acreage position in Hopkins County, Texas, and coordinated pipeline development and the drilling of a discovery well in that field.

Mr. Griffin brings 38 years of broad business development and management experience to the Company. Prior to his involvement in the oil and gas industry, he was directly responsible for the development, financing and construction of more than $35,000,000 worth of multi-family and senior housing projects.

Mr. Griffin graduated from East Texas State University in May of 1975 with a degree in Finance and Business Management.

Because of Mr. Griffin's specific experience in, and knowledge of, the oil and gas industry, and as an entrepreneur and founder of MEI, we have concluded that Mr. Griffin should serve as a director and Chairman of the Company.

Rachel L. Dillard, CPA joined Mesa as Chief Financial Officer in September of 2011 and became Chief Financial Officer of Armada upon the closing of the Mesa Acquisition in March of 2013.

Ms. Dillard began her career in oil and gas in 1996 with CDX Gas, LLC. In an association that concluded at the end of 2006, she served CDX both as a consultant to the CEO and CFO and as an employee in matters of financial analysis, natural gas marketing and balancing, investor relations and payout analysis. During that period, Ms. Dillard also served as an accountant and consultant for Rising Star Energy, LLC, Republic Energy, Inc., and Longview Production Company. As Director of Financial Services, she centralized management of fixed assets and implemented the process of automated calculation and recording of depletion, depreciation, and amortization of pools of fixed assets of approximately $500 million.

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From February to May 2007, she consulted with TransAtlantic Petroleum Corporation as Interim Controller in preparation for its divestiture of its US properties. As such, she prepared the sale price allocation of divested properties, prepared the oil & gas property section of 2006 form 10-K and Q1 2007 10-Q under full-cost accounting method, consulted with engineers in their preparation of 2006 reserve reports under both constant costs and pricing (SEC case) and escalated costs and pricing (NYMEX case) and handled inquiries from auditors.

In June 2007, she joined Westside Energy Corporation as its Corporate Controller, serving Westside through its merger in June 2008 with Crusader Energy Group, Inc. At Westside, she directed financial reporting; prepared consolidated financial statements and reports on Forms 10-K and 10Q using the successful efforts method of accounting for oil & gas properties and spearheaded Westside's Sarbanes-Oxley compliance project.

Following Westside's merger with Crusader, Ms. Dillard consulted with Crusader on various transition matters. In 2009, Ms. Dillard joined the Division of Resolutions and Receiverships of the Federal Deposit Insurance Corporation as a contractor. In March 2010 she was engaged by the FDIC as Financial Institution Accountant and, in January 2011, as Accounting Technical Monitor, under the FDIC Contract Management and Oversight function, of a national servicer of a loan portfolio exceeding $1 billion.

Ms. Dillard earned her Bachelor of Science Degree in Business Administration with an Emphasis in Accounting, cum laude, from The University of Texas at Dallas. She is licensed by the State of Texas as a Certified Public Accountant and is a member of the American Institute of Certified Public Accountants, from which she holds the credential of Chartered Global Management Accountant (CGMA), and the Texas Society of Certified Public Accountants. Ms. Dillard is also a member of American Mensa.

James J. Cerna, Jr. served as the President and Chief Executive Officer of Armada until the closing of the Mesa Acquisition in March of 2013, Since the closing of the Mesa Acquisition, Mr. Cerna has served as President of Armada. From May 2006 to May 2009, Mr. Cerna served as Chairman of the Board of Lucas Energy, Inc. (NYSE Amex: LEI), and was also CEO and President thereof from May 2006 until September 2008. From 2004 to 2006, Mr. Cerna was President of the privately held Lucas Energy Resources.

Prior to joining Lucas Energy, Mr. Cerna was the Chief Oil and Gas Analyst and CFO of Petroleum Partners LLC from 2001 to 2004. He was the founder and CEO of NetCurrents, Inc., (NASDAQ: NTCS), an organization that focuses on Internet information monitoring and analysis. Prior to NetCurrents, Mr. Cerna was the manager of the GT Global/AIM Funds performance analysis group in San Francisco. Mr. Cerna has received five certificates of achievement from the Institute of Chartered Financial Analysts. He is honored by Strathmore's Who's Who for leadership and achievement in the Finance Industry. Mr. Cerna is the Public Affairs Officer and Pilot with the Civil Air Patrol, U.S. Air Force Auxiliary, Squadron 192.

Mr. Cerna received a BS in Finance from the California State University, Chico, in 1990.

Because of Mr. Cerna's broad experience in, and knowledge of, the oil and gas industry, and his extensive experience in working with publicly traded companies, we have concluded that Mr. Cerna should serve as a director of the Company.

J. Clint Unruh serves as Executive Vice President of Land and Administration for Armada. He is responsible for the oversight of all land activities as well as a number of day to day administrative functions.

In May of 2003, Mr. Unruh joined Mesa Energy, LLC, where he served as Vice President until May of 2007. During that time, Mr. Unruh was responsible for various administrative functions as well as the negotiation and acquisition of right-of-way for a midstream natural gas pipeline in Sequoyah County, Oklahoma.

In May of 2007, Mr. Unruh left Mesa Energy, LLC, to form Shiloh Homes, LLC, a residential and commercial construction company that he owned and operated until December of 2010. Wanting to return to the oil and gas industry, in January of 2011 Mr. Unruh left Shiloh Homes, LLC, and joined Percheron Acquisitions, LLC, where he served as a right-of-way agent and area manager overseeing the acquisition and construction of 5 midstream gathering systems for Pioneer Natural Resources Company. In February of 2012, Mr. Unruh returned to Mesa Energy, Inc., to serve as Vice President.

Mr. Unruh earned a Bachelor of Business Administration in Finance from Texas A&M University and a Professional Land Management Certification from the University of Houston Downtown. He is a Registered Landman with, and an active member of the American Association of Professional Landmen, a member of the Dallas Association of Petroleum Landmen, and a member of the Independent Petroleum Association of America.

Ray L. Unruh is one of the founders of Mesa and served as its President until the closing of the Mesa Acquisition in March of 2013, at which time he became the Corporate Secretary of Armada.

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From March 1999 until March 2003, Mr. Unruh served as the Vice-President of Santa Fe Petroleum, LLC, and the President of its operating affiliate, TexTron Southwest, LLC. During that period, he performed a variety of administrative and executive functions for both companies in connection with the oil and gas development and exploration activities undertaken by those companies in Shelby County, Texas. During Mr. Unruh's tenure, TexTron drilled 21 horizontal James Lime wells in Shelby County, Texas, and TexTron became the largest gas producer in the county. Of the 2l wells drilled by TexTron in that field, 18 were commercially successful. As of January 2006, those wells had produced nearly 25 billion cubic feet (BCF) of gas and over 60,000 barrels of oil. In September 2002, TexTron drilled a Smackover oil well in Hopkins County, Texas, which was classified as a new field discovery well and produced, through April 2007, over 459,000 barrels of oil. Mr. Unruh left Santa Fe Petroleum, LLC, and TexTron Southwest, LLC, in March 2003 with Mr. Griffin to form and operate Mesa Energy, LLC.

Mr. Unruh owned and operated Red River Energy Supply Company, an oil field equipment company, in the early 1980 s. Between 1990 and 1998, he performed management and financial consulting services for Texas Northern Oil Company and for Phoenix Resources, LLC.

Mr. Unruh attended Oklahoma State University, where he majored in Business Administration and Finance.

Because of Mr. Unruh's specific experience in, and knowledge of, the oil and gas industry, including his history of working with MEI and its predecessor company since its inception, we have concluded that Mr. Unruh should serve as a director of the Company.

Kenneth T. Hern was appointed to the Mesa Board of Directors in January of 2010 and to the Armada Board of Directors in May of 2012. In addition, Mr. Hern currently serves, and has served since November 2009, on the Board of Directors and as Chairman of the Governance Committee of Flotek Industries, Inc. (NYSE: FTK), a supplier of drilling and production related products and services to the energy and mining industries.

Mr. Hern also served as Chairman of the Board and CEO of Nova Biosource Fuels, Inc. (NYSE Amex: NBF) (Nova), a leading provider of biodiesel fuel, and held that position from December 2, 2005 to April 2010.

Nova filed Chapter 11 in April 2009 seeking protection under federal bankruptcy statutes. By October 2010, the court approved dismissal of all Nova entities.

From January 2003 to December 2005, Mr. Hern was Chairman of the Board of Homeland Renewable Energy LLC, a privately held holding company of Fibrowatt LLC.   Fibrowatt LLC is a developer, builder, owner and operator of poultry litter-fueled power plants, and is based in Pennsylvania.

From 1969 to 1994, Mr. Hern served in several capacities at Texaco, Inc., including President and Chairman of the Board of Texaco Brazil from 1989 to 1994.

Mr. Hern earned a B.A. in Chemistry from Austin College in 1960 and an M.S. in Organic Chemistry from North Texas State University in 1962.

Mr. Hern also received Associates Degrees from the Wharton School of Business and from Carnegie Mellon University in 1990 and 1991, respectively.

Because of Mr. Hern's extensive experience in, and knowledge of, the oil and gas industry, including his history of working with publically traded companies and well as entrepreneurial private companies, we have concluded that Mr. Hern should serve as a director of the Company.

Fred B. Zaziski was appointed to the Board of Directors of Mesa in January of 2010 and became a director of Armada upon closing of the Mesa Acquisition in March of 2013.

Mr. Zaziski was President and CEO of Epsilon Energy Ltd. (TSX: EPS), a publicly traded exploration and production company based in Toronto and Houston, from June 2007 to May 2009.

From March 2007 until July 2008, Mr. Zaziski served as President and Chairman of PetroSouth Energy Corp. (OTCBB: PSEG), another publicly traded exploration and production company based in Houston, and from October 2004 to January 2007, he served as President, CEO and a Director of Falcon Natural Gas Corp., Houston (FNGC.PK). Prior to 2004, Mr. Zaziski worked in a number of senior management capacities for a number of other oil & gas companies including National Petroleum Technology Company, Saudi Arabia (1997 –1999) and Halliburton Energy Services, Bahrain (1977 –1997).

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Mr. Zaziski graduated from Pennsylvania State University with a BSc, in petroleum engineering in 1976. He received an MBA in Organizational Management and a Masters in International Business from Cairo University, Egypt in 1986 and 1987, respectively. He is a member of the Society of Petroleum Engineers, the American Petroleum Institute and the American Society of Mechanical Engineers.

Because of Mr. Zaziski's specific experience in, and knowledge of, the oil and gas industry, including his history of working in management capacities with a number of publicly traded oil and gas exploration and development companies, we have concluded that Mr. Zaziski should serve as a director of the Company.

Marceau N. Schlumberger joined the Board of Directors of Armada in March of 2013. He is a Partner and Founder of Coral Reef Capital ("CRC"), a private equity firm focused on investments in the natural resources sector, including oil & gas exploration and production, metals & mining, energy and related infrastructure and services. Prior to founding CRC, he served as Principal of Columbus Nova from 2004 to 2008 where he was responsible for sourcing, structuring, negotiating and managing private equity investments and buyouts, leading several successful transactions such as the leveraged buyout of Cyalume Technology Holding, Inc., as well as land finance and development partnerships with Hovnanian Enterprises, Inc.

Prior to that, Mr. Schlumberger was an Associate at Triumph Capital, a private equity fund with $950 million of capital where he completed seven investments, assisted in the profitable sale of two portfolio companies and served as a Board Observer for several Triumph portfolio companies. He was also a founding member and analyst of Smith Barney's Asia Investment Banking Group and an analyst at Zilkha & Co., a buy-side M&A advisory and merchant banking firm.

In addition to Armada Oil, Mr. Schlumberger currently serves on the Board of Directors of the following private companies: Shawnee Exploration, Microline Surgical Inc. (member of the Compensation Committee), Rawhide Mining, LLC (Chairman of the Audit Committee), and PF Leonville. He previously served on the Boards of the following private companies: Pacific Building Care, Cyalume Technologies, Inc. (now public), ISCON Video Imaging and Craig Michaels, Inc. Mr. Schlumberger has served on the Board of Directors of Miller Energy Resources, Inc., a NYSE listed company, since July 29, 2013 and is a member of this company's compensation committee.

Mr. Schlumberger received a BA from Yale University and an MBA from The Wharton School.

Because of Mr. Schlumberger's service on various public and private company boards of directors and his knowledge and experience related to natural resource finance transactions, we have concluded that Mr. Schlumberger should serve as a director of the Company.

Eric Wold joined the Board of Directors of Armada in May of 2012.

Mr. Wold previously served on the Board of Directors of Lucas Energy (AMEX:LEI), a publicly held company within the oil and energy sector from 2005-2009. He is currently a Senior Analyst with B. Riley & Co., a leading full-service investment bank, where he has more than 18 years of buy-side and sell-side equity research experience, reporting on a dozen companies in the Internet and Media and Entertainment sectors with market caps between $50 Million and $6 Billion, including Tivo, Inc., Netflix, Inc. and Coinstar, Inc. Previously, Mr. Wold held the position of Managing Director, Equity Research at the investment banking firm Merriman Capital, Inc., where he covered the Branded Global Consumer and Media Groups. He was also Director of Corporate Finance with NightFire Software, a privately held telecommunications software company based in Oakland, California. At First Security Van Kasper, he served as Vice President and Senior Research Analyst, where he was responsible for the Restaurant and Branded Consumer sectors. Mr. Wold began his career on the buy-side with research analyst positions with both Polynous Capital Management (a hedge fund that he co-founded in 1996) and GT Global Financial Services. He received his Chartered

Financial Analyst (CFA) designation in 1997 and a Bachelor’s degree in Finance from the University of California at Berkeley.

Because of Mr. Wold’s s prior service on a public company board of directors and his extensive background in finance and public markets, we have concluded that Mr. Wold should serve as a director of the Company.

Director Qualifications

The Board believes that each of our directors is highly qualified to serve as a member of the Board. Each of the directors has contributed to the mix of skills, core competencies and qualifications of the Board. When evaluating candidates for election to the Board, the Board seeks candidates with certain qualities that it believes are important, including integrity, an objective perspective, good judgment, and leadership skills. Our directors are highly educated and have diverse backgrounds and talents and extensive track records of success in what we believe are highly relevant positions.

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Involvement in Certain Legal Proceedings

To the best of our knowledge, except as disclosed above, none of our existing directors or executive officers have been the subject of any bankruptcy petition filed by or against any business of which such person was a general partner or executive officer either at the time of the bankruptcy or within two years prior to that time, been convicted in a criminal proceeding or been subject to a pending criminal proceeding (excluding traffic violations and other minor offenses), been subject to any order, judgment or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining, barring, suspending or otherwise limiting such person's involvement in any type of business, securities or banking activities or been found by a court of competent jurisdiction (in a civil action), the SEC or the Commodity Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended or vacated.

Board Independence

We are currently not required to have any independent members of the Board of Directors. The Board of Directors has determined that (i) Messrs. Griffin, Cerna and Unruh have relationships which, in the opinion of the Board of Directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director and each is not an "independent director" as defined in the Marketplace Rules of The NASDAQ Stock Market and (ii) Messrs. Hern, Schlumberger, Wold and Zaziski are each an independent director as defined in the Marketplace Rules of The NASDAQ Stock Market.

Board Committees

We are not currently subject to listing requirements of any national securities exchange or inter-dealer quotation system which requires us to have committees or charters. Our Board of Directors, however, has determined to establish three committees: an Audit Committee; a Compensation Committee; and a Nominating and Corporate Governance Committee. Each committee operates under a charter approved by our Board of Directors. Each charter is available, free of charge, on our website at www.armadaoil.us. The membership, principal duties, and responsibilities of each committee are set forth below.

The membership of our Board committees is as follows:

Audit Committee – Eric C. Wold (Chairman), Kenneth T. Hern, and Marceau N. Schlumberger

Compensation Committee – Fred B. Zaziski (Chairman), Kenneth T. Hern and Eric C. Wold

Corporate Governance – Kenneth T. Hern (Chairman), Fred B. Zaziski and Marceau N. Schlumberger.

Audit Committee

The committee's charter provides that the principal duties and responsibilities of the Audit Committee include:

- reviewing and discussing certain regulatory filings, including our audited financial statements and quarterly financial statements, with management and our independent auditors;

- reviewing earnings press releases and earnings guidance provided to analysts;

- appointing, evaluating, overseeing and replacing, if necessary, our independent registered public accounting firm;

· reviewing the design, implementation, adequacy and effectiveness of our internal controls and our critical accounting policies;

· reviewing our compliance with applicable laws, rules and regulations, and reviewing cases of employee misconduct or fraud; and

· reporting regularly to our Board of Directors with respect to issues relating to the quality or integrity of our financial statements, our compliance with legal or regulatory requirements and the performance and independence of our independent auditors.

All audit and non-audit services, other than de minimis non-audit services, provided to us by our independent registered public accounting firm must be approved in advance by our audit committee.

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Compensation Committee

The committee's charter provides that the principal duties and responsibilities of the Compensation Committee include:

- reviewing and approving annual goals and objectives of our CEO and other executive officers, evaluating the performance of our CEO and other executive officers in light of those goals and objectives, determining or assisting to determine our CEO's and other executive officers' compensation level and making all other determinations with respect to the compensation of our CEO and other executive officers;

- recommending to our Board of Directors the compensation of our CEO and other executive officers and, to the extent such authority is delegated to it by our Board of Directors, approving the compensation payable to these executive officers;

- considering with respect to the compensation of the Company's executive officers: (a) annual base salary; (b) any bonus or other short-term incentive program; (c) any long-term incentive compensation (including cash-based and equity-based awards); and (d) any employment agreements and similar arrangements or transactions;

- reviewing and administering our stock and incentive compensation plans, establishing criteria for the granting of options or other incentive awards to executive officers and other employees and reviewing and approving the granting of awards in accordance with such criteria and making recommendations to our Board of Directors regarding changes to our incentive compensation and equity-based plans that are subject to approval by our Board of Directors;

- reviewing and making recommendations to our Board of Directors regarding compensation, if any, of the Board of Directors and its committees; and

- preparing a report of the committee for inclusion in our annual report or proxy statement with respect to our annual meeting of stockholders.

Nominating and Corporate Governance Committee

The committee's charter provides that the principal duties and responsibilities of the Nominating and Corporate Governance Committee include:

- identifying, evaluating and selecting or recommending for selection candidates for election to our Board of Directors;

- evaluating the functions, duties and composition of committees of our Board of Directors and making recommendations to our Board of Directors with respect thereto;

- formulating procedures for security holders to send communications to our Board of Directors;

- developing and recommending to our Board of Directors a set of corporate governance policies or procedures;

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establishing and maintaining an informal orientation and continuing education program for our directors with respect to our strategic plans, significant financial, accounting and risk management matters, compliance programs, corporate governance policies or procedures, principal officers and internal and independent auditor; and

- developing a plan for the succession of our CEO and discussing with our CEO a succession plan for our key senior officers.

The Nominating and Corporate Governance Committee of the Board of Directors is responsible for reviewing with the entire Board from time to time the appropriate skills and characteristics required of Board members in the context of the current make-up of the Board of Directors. The Board of Directors believes that directors should bring to the Company a variety of perspectives and skills that are derived from high quality business and professional experience and that are aligned with the Company's strategic objectives. The composition of the Board of Directors should at all times adhere to the standards of independence promulgated by applicable NASDAQ and SEC rules. We also require that our directors be able to attend all board and applicable committee meetings. In this respect, directors are expected to advise the Chairman of the Board of Directors and the Chairman of the Nominating and Corporate Governance Committee in advance of accepting any other public company directorship or assignment to the audit committee of the board of any other public company.

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The Nominating and Corporate Governance Committee identifies nominees by first evaluating the current members of the Board of Directors willing to continue in service. Current members of the Board with skills and experience that are relevant to the Company's business and who are willing to continue in service are considered for re-nomination, balancing the value of continuity of service by existing members of the Board with that of obtaining a new perspective. If any member of the Board does not wish to continue in service or if the Nominating and Corporate Governance Committee or the Board decides not to re-nominate a member for re-election, the Committee will identify the desired skills and experience of a new nominee in light of the criteria above. Current members of the Committee and Board may be consulted for suggestions as to individuals meeting the criteria above. Research may also be performed to identify qualified individuals.

Code of Ethics

We have adopted a formal Code of Ethics applicable to our directors, officers, and employees. Our Code of Ethics is available free of charge on our website at www.armadaoil.us.

Shareholder Communications

Currently, we do not have a policy with regard to the consideration of any director candidates recommended by security holders. To date, no security holders have made any such recommendations.

Compliance with Section 16(a) of the Exchange Act

Section 16(a) of the Exchange Act requires our executive officers and directors and persons who own more than 10% of a registered class of our equity securities to file with the SEC initial statements of beneficial ownership, reports of changes in ownership and annual reports concerning their ownership of our common stock and other equity securities, on Form 3, 4 and 5 respectively. Executive officers, directors and greater than 10% shareholders are required by the SEC regulations to furnish our company with copies of all Section 16(a) reports they file.

We registered our common stock pursuant to Section 12 of the Exchange Act by filing a Form 8-A with the SEC on January 15, 2014. Accordingly, our officers, directors and 10% shareholders were not subject to the beneficial ownership reporting requirements of Section 16(a) of the Exchange Act with respect to our fiscal year ended December 31, 2013.

ITEM 11. EXECUTIVE COMPENSATION

The following table sets forth information concerning the total compensation paid or accrued by us during the last two fiscal years ended December 31, 2013, to (i) all individuals that served as our principal executive and principal financial officers or acted in a similar capacity for us at any time during the fiscal year ended December 31, 2013; (ii) our two most highly compensated executive officers other than the principal executive and principal financial officers who were serving as executive officers at the end of the fiscal year ended December 31, 2013, and who received annual compensation during the fiscal year ended December 31, 2013 in excess of $100,000; and (iii) up to two additional individuals who received annual compensation during the fiscal year ended December 31, 2013 in excess of $100,000 and who were not serving as executive officers of at the end of the fiscal year ended December 31, 2013.

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Summary Compensation Table

Name & Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Randy M. Griffin, Chief Executive Officer (1)(2)(3)(4)	2013	$ 210,000	$ —	$ —	$ 199,766	—	—	—	$ 409,766
	2012	$ 190,000	$ 5,000	$ —	$ 68,938	—	—	—	$ 263,938
Rhonda B. Rosen (2)(5)	2013	$ 18,000	—	$ —	$ 54,834	—	—	—	$ 72,834
	2012	$ 48,000	—	$ —	—	—	—	—	$ 48,000
Rachel L. Dillard, Chief Financial Officer (2)	2013	$ 125,000	$ 8,000	$ —	$ 57,283	—	—	—	$ 190,283
	2012	$ 115,250	$ 8,000	$ 73,846	—	—	—	—	$ 197,096
David L. Freeman, Chief Operating Officer (2)(6)	2013	$ 199,993	$ 8,000	$ 13,200	—	—	—	—	$ 207,993
	2012	$ 200,000	$ 5,000	$ 15,000	—	—	—	—	$ 220,000
James J. Cerna, Jr., President (2)(7)	2013	$ 153,554	$ 5,000	$ 3,300	$ 229,939	—	—	—	$ 391,793
	2012	$ 180,000	$ —	$ 3,750	$ 9,416	—	—	—	$ 193,166
J. Clint Unruh, Executive Vice President (2)	2013	$ 111,000	$ 5,000	—	$ 11,049	—	—	—	$ 127,049
	2012	$ 96,182	$ 2,500	—	$ 9,404	—	—	—	$ 108,086

(1) Mr. Griffin became our Chief Executive Officer on March 28, 2013.
(2) Value of stock and option awards is the actual amount of stock compensation expense recognized in 2013 for the awards. The fair values of the awards on the date of grant were: Mr. Griffin, $337,644; Ms. Dillard, $225,283; Mr. Freeman, $30,000; Mr. Cerna, $247,903; Mr. Unruh, $23,510, Ms. Rosen, $54,834.
(3) Mr. Griffin's 2012 reported salary does not include $120,000 paid to him as part of accrued salary from prior years which was paid to him in increments of $10,000 per month.
(4) Mr. Griffin's 2013 reported salary does not include $37,500 paid to him as part of accrued salary from prior years which were paid to him in increments of $10,000 per month.
(5) Ms. Rosen served as our Chief and Principal Financial Officer from May 1, 2012, until March 28, 2013.
(6) Mr. Freeman is no longer our Chief Operating Officer effective February 16, 2014
(7) Mr. Cerna served as our Chief and Principal Executive Officer from July 29, 2011 until March 28, 2013.

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Employment Agreements with Executive Officers

On April 1, 2013, the Company entered into an employment agreement with Mr. Griffin as its Chief Executive Officer. The employment agreement provides for (i) an annual base salary of $210,000 per year, subject to annual increase at the Board of Directors' discretion. If Mr. Griffin's employment is terminated without Cause during the first year of the agreement, or if he resigns for Good Reason (as defined in his agreement), he will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which he was a participant immediately prior to his last date of employment with the Company for a period of six months following such cessation of employment. If such a termination should occur during the second year of the agreement or thereafter, the severance period is reduced to three months The term of the employment agreement is for a period of two years and automatically renews for successive one year periods thereafter unless terminated pursuant to the agreement. Prior to April 1, 2013, Mr. Griffin's compensation was governed by an employment agreement with Mesa. Under the terms of that agreement, Mr. Griffin was entitled to an annual base salary of $180,000 in 2012. Mr. Griffin offered forbearance to the Company for payment of his salary for the period September 1, 2009 through July 31, 2011. Beginning January 1, 2012, the Company made monthly payments of $10,000 to Mr. Griffin until the accrued salary was repaid to him in full in 2013.

On September 19, 2011, Mesa entered into an employment agreement with Rachel L. Dillard, its Chief Financial Officer, which agreement was assumed by Armada upon the closing of the Mesa Acquisition. The employment agreement, as amended, provides for an annual base salary of $134,375. If Ms. Dillard's employment is terminated without Cause, or if she resigns for Good Reason (as defined in her agreement), she will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which she was a participant immediately prior to her last date of employment with the Company for a period of three months following such cessation of employment. The original term of the employment agreement was for a period of twelve months and it automatically renews for one year periods thereafter unless terminated pursuant to the agreement. Any unvested equity compensation vests upon Ms. Dillard's death or disability. Under the employment agreement with Mesa, Ms. Dillard received restricted stock awards totaling 1,200,000 shares. 600,000 of those restricted shares were vested as of the date of the Mesa Acquisition and were exchanged for 240,000 shares of Armada common stock. The remaining 600,000 shares under the Mesa restricted shares awards were converted in March 2013 to Mesa incentive stock options which were assumed by Armada upon the closing of the Mesa Acquisition. Under this assumption, Ms. Dillard received options to purchase 240,000 shares of Armada common stock exercisable at a price of $0.33 per share and expiring on March 20, 2018.

On April 1, 2013, the Company entered into an employment agreement with James J. Cerna, Jr., its President. The employment agreement provides for (i) an annual base salary of $144,000, subject to annual increase at the Board of Directors' discretion. If Mr. Cerna's employment is terminated without Cause, or if he resigns for Good Reason (as defined in his agreement), he will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which he was a participant immediately prior to his last date of employment with the Company for a period of six months following such cessation of employment. If such a termination should occur during the second year of the agreement or thereafter, the severance period is reduced to three months. The term of the employment agreement is for a period of two years and automatically renews for successive one year periods thereafter unless terminated pursuant to the agreement. Prior to April 1, 2013, Mr. Cerna received an annual salary of $180,000 plus reimbursement for health benefits.

While the Company does not have a written employment agreement with J. Clint Unruh, we have agreed to pay Mr. Unruh an annual salary of $120.000.

Grants of Plan-Based Awards

We have not issued any stock options or maintained any stock option or other incentive plans other than our 2012 Long-Term Incentive Plan. (See “Market for Common Equity and Related Stockholder Matters – Securities Authorized for Issuance under Equity Compensation Plans,” above).

During the year ended December 31, 2013, options to purchase 500,000 shares were granted to each of Randy M. Griffin and James J. Cerna, Jr.; and options to purchase 600,000 shares of the Company’s common stock were granted to Rachel L. Dillard in conjunction with the cancellation of two unvested previous Mesa restricted stock grants of the same number of shares of restricted stock. These options were, at consummation of the Mesa Acquisition] converted to options to purchase 240,000 shares of the Company’s common stock. A previous grant of options by Mesa to Mr. Cerna to purchase 250,000 shares, converted at consummation of the Mesa Acquisition to options to purchase100,000 shares of the Company’s common stock, was cancelled and replaced with a grant of options to purchase 150,000 shares of the Company’s common stock.

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Outstanding Equity Awards at Fiscal Year End

The following tables set forth information regarding stock options held by our Named Executive Officers at December 31, 2013.

		Option Awards			
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Option Exercise Price ($/Sh)	Option Expiration Date
Randy M. Griffin	4/19/2013	500,000	—	0.40	4/1/2018
	6/30/2011	400,000	—	0.38	6/30/2016
Rachel L. Dillard	3/20/2013	240,000	—	0.33	3/20/2018
James J. Cerna, Jr.	12/31/2013	150,000	—	0.40	12/31/2017
	4/19/2013	500,000	—	0.40	4/1/2018
	6/8/2012	20,000	20,000	0.36	1/5/2015
J. Clint Unruh	2/10/2012	40,000	—	0.65	2/10/2017

Option Exercises and Stock Vested Table

The following tables set forth information regarding vested restricted stock awards held by our Named Executive Officers at December 31, 2013.

	Stock Awards	
Name	Number of Shares of Restricted Stock Acquired on Vesting	Value Realized on Vesting ($)
Rachel L. Dillard	240,000	$ 90,000
David L. Freeman	80,000	$ 30,000

(1) The value realized on vesting is based on the number of Mesa shares awarded on the date of grant, which preceded the Mesa Acquisition, times the closing market price on the date of grant ($0.15). Upon consummation of the Mesa Acquisition, the Mesa shares previously awarded were exchanged for Armada shares and grants in accordance with the exchange ratio of one Armada share for every 2.5 Mesa shares exchanged (the "Exchange Ratio"). In order to avoid altering the fair values of the grants, the grant date market price of Mesa shares was divided by the Exchange Ratio, resulting in the fair value per Armada share increasing by the same Exchange Ratio by which the Mesa granted shares were reduced, resulting in no change in the fair value of the awards. The resulting fair value price per share was calculated to be $0.375.

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Director Compensation

The following table sets forth summary information concerning the total compensation paid to our non-employee directors in 2013 for services to us.

Name	Fees Earned or Paid in Cash($)	Stock Option Awards ($)(1)	Restricted Stock Awards ($)(2)	Total ($)
Kenneth T. Hern	9,750	63,132	3.300	76,182
Fred B. Zaziski	9,750	39,049	3,300	52,099
Ray Unruh	6,750	16,581	9,900	33,231
Marceau N. Schlumberger	6,750	16,581	—	23,331
Eric Wold	6,750	43,209	—	49,959
Total:	$ 39,750	$ 178,552	$ 16,500	$ 234,802

(1) On December 31, 2013, vested options held by our nonemployee directors (Messrs. Hern, and Zaziski) representing 200,000 shares exercisable at $0.63 per share; 50,000 shares held by Mr. Wold exercisable at $1.45 per share; and 50,000 shares held by Mr. Hern exercisable at $1.60 per share were cancelled and replaced with options representing 300,000 shares (Messrs. Hern, 150,000 shares; Mr. Zaziski 100,000 shares, and Mr. Wold 50,000 shares) exercisable at $0.40 per share, expiring on December 31, 2017. Vesting was immediate upon grant, and associated stock compensation expense of $56,163 was recognized in 2013.

On April 19, 2013, our nonemployee directors were granted restricted stock option awards, vesting over one year, with half vesting at grant and half vesting on the first year anniversary of the grant, as follows:

Name	Number of shares	Fair Value	2013 Stock Compensation Expense
Kenneth T. Hern	55,000	$ 21,417	$ 18,237
Fred B. Zaziski	55,000	21,417	18,237
Ray Unruh	50,000	19,470	16,581
Marceau N. Schlumberger	50,000	19,470	16,581
Eric Wold	60,000	23,364	19,896
	270,000	$ 105,138	$ 89,531

These options expire April 1, 2018 and have an exercise price of $0.40 per share.

On June 8, 2012, each of our non-employee directors, Messrs. Hern and Zaziski, was granted restricted stock option awards of 40,000 shares of our common stock vesting over a period of one year as follows: 20,000 shares on June 8, 2013 and 20,000 shares on June 8, 2014. We determined the fair value of each of these awards on the date of grant to be $12,556. Options expire on June 7, 2017 and have an exercise price of $0.37 per share.

On September 30, 2011, each of our non-employee directors, Messrs. Hern and Zaziski, was granted a restricted stock award of 20,000 shares of our common stock vesting over a period of two years as follows: 2,000 shares on December 30, 2011, 4,000 shares on each of March 30, 2012, September 30, 2012 and March 30, 2013 and 15,000 shares on September 30, 2013. We determined the fair value of each of these awards on date of grant to be $7,500; and, 2013 stock compensation expense recognized for these awards was $6,600 in the aggregate. On September 30, 2011, our non-employee director, Mr. Ray L. Unruh, was granted a restricted stock award of 60,000 shares of our common stock vesting over a period of two years as follows: 18,000 shares on March 30, 2012, 12,000 shares vesting on each of September 30, 2012 and March 30, 2013, and 18,000 shares vesting on September 30, 2013. We determined the fair value of this award on the date of grant to be $22,500, and 2013 stock compensation expense recognized for this award was $9,900 in the aggregate.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information with respect to the beneficial ownership of our common stock known by us as of March 31, 2014 by:

- each person or entity known by us to be the beneficial owner of more than 5% of our common stock;
- each of our directors and executive officers; and
- all of our directors and executive officers as a group.

Name and Address of Beneficial Owner 1	Amount and Nature of Beneficial Ownership 2	Percentage of Class 3
Randy M. Griffin	(4) 5,292,136(13)	9.3%
Ray L. Unruh	(5) 3,268,717(13)	5.8%
James J. Cerna, Jr.	3,187,333(6)	5.6%
J. Clint Unruh	495,000(7)	*
Rachel L. Dillard	480,000(8)	*
Kenneth T. Hern	245,000(9)	*
Fred B. Zaziski	195,000(10)	*
Eric Wold	186,954(11)	*
Marceau N. Schlumberger	96,667(12)	*
All directors and executive officers as a group (9 persons)	13,446,807(13)	23.8%
David Moss	3,998,833(14)	7.1%
David L. Freeman	3,393,533(15)	6.1%

* Indicates beneficial ownership of less than 1%.

1 Unless otherwise noted, the mailing address of each beneficial owner is c/o Armada Oil, Inc., 5220 Spring Valley Road, Suite 615, Dallas, Texas 75254. Data is based on information furnished to us by the named officers and directors.

2 Beneficial ownership is determined in accordance with the rules of the SEC and generally includes having or sharing voting or investment power with respect to securities. Shares of common stock subject to options or warrants currently exercisable or convertible, or exercisable or convertible within 60 days of March 28, 2014, are deemed outstanding for computing the percentage of the person holding such option or warrant but are not deemed outstanding for computing the percentage of any other person.

3 Percentages are based upon 56,030,473 shares of Common Stock issued and outstanding as of March 28, 2014.

4 Includes 694,296 shares owned by Amagosa Investments Ltd. ("Amagosa") Mr. Griffin, as General Partner of Amagosa, has sole voting and investment control with respect to our shares held by Amagosa. Also includes 761,600 shares owned by Sycamore Resources, Inc. ("Sycamore") Mr. Griffin, as the sole shareholder of Sycamore, has sole voting and investment control with respect to our shares held by Sycamore. Also includes an aggregate of 720,000 shares of common stock that may be purchased from Ray Unruh pursuant to option agreements dated December 17, 2012. Also includes 900,000 shares of our common stock issuable upon the exercise of options granted under our 2012 Incentive Plan.

5 Includes 310,332 shares owned by Ray L. Unruh Profit Sharing Plan (the "Unruh Plan"), of which Mr. Unruh is a trustee and has voting and investment control with respect to our shares held by the Unruh Plan and 2,158,385 shares owned by Unruh & Unruh Properties Ltd. Mr. Unruh, as President of the General Partner of Unruh & Unruh Properties Ltd. has voting and investment control with respect to our shares held by these entities. Includes the 720,000 shares owned by Ray Unruh that may be purchased by Randy Griffin pursuant to option agreements dated December 17, 2012. Also includes options to purchase 25,000 shares of our common stock vested under our 2012 Incentive Plan and options to purchase an additional 25,000 shares, which options are exercisable within 60 days of March 31, 2014.

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6 Includes 670,000 shares of our restricted common stock issuable upon the exercise of vested options granted under our 2012 Incentive Plan. Also includes Series D warrants to purchase 133,333 shares of our restricted common stock issued in conjunction with the Company's 2012 unit private placement. Does not include an additional 20,000 shares of our restricted common stock issuable upon vesting on June 8, 2014.

7 Includes 28,000 shares of our restricted common stock issuable upon the exercise of options granted under our 2012 Incentive Plan and an additional 12,000 shares of our restricted common stock issuable upon the exercise of options vesting on March 30, 2014.

8 Includes 240,000 shares of our restricted common stock issuable upon the exercise of vested options granted under our 2012 Incentive Plan.

9 Includes 197,500 shares of our restricted common stock issuable upon the exercise of vested options granted under our 2012 Incentive Plan and 27,500 shares of our restricted common stock that will become issuable upon the exercise of options vesting on April 19, 2014. Does not include options to purchase 20,000 shares of our restricted common stock issuable upon the exercise of options which will vest on June 8, 2014.

10 Includes 147,500 shares of our restricted common stock issuable upon the exercise of vested options granted under our 2012 Incentive Plan and 27,500 shares of our restricted common stock that will become issuable upon the exercise of options vesting on April 19, 2014. Does not include options to purchase 20,000 shares of our restricted common stock issuable upon the exercise of options which will vest on June 8, 2014.

11 Includes 80,000 shares of our restricted common stock issuable upon the exercise of options granted under our 2012 Incentive Plan and 30,000 shares of our restricted common stock that will become issuable upon the exercise of options which will vest on April 19, 2014.

12 Includes 25,000 shares of our restricted common stock issuable upon the exercise of options granted under our 2012 Incentive Plan and 25,000 shares of our restricted common stock that will become issuable upon the exercise of options vesting on April 19, 2014. Also includes warrants to purchase 46,667 shares of our restricted common stock issued in conjunction with the Company's 2012 unit private placement.

13 As Mr. Griffin has an option to purchase an aggregate of 720,000 shares of common stock from Ray Unruh, such shares have been included as beneficially owned by each of Messrs. Griffin and Unruh, both of whom are our officers and directors. However, such 720,000 shares have only been included once in the beneficial ownership of all officers and directors as a group, since a purchase of the shares by Mr. Griffin would increase his share ownership while proportionally decreasing Mr. Unruh's ownership.

14 Includes Series D warrants to purchase 373,333 shares of our restricted common stock issued in conjunction with the Company's 2012 unit private placement.

15 Includes 1,388,592 shares owned by Freeman Energy LLC and 1,464,933 shares owned by H S Investments LLC. Mr. Freeman, as the sole Member of each of these entities has sole voting and investment control with respect to our shares held by such entities.

Equity Compensation Plan Information

On September 30, 2002, the stockholders of the Company approved its 2002 Incentive Stock Plan (the “2002 Plan”), which had 4,000,000 shares reserved for issuance thereunder. The 2002 Stock Plan expired in September 2012. In anticipation of its expiration, by way of Unanimous Written Consent dated April 27, 2012, the Board of Directors (the “Board”) approved the terms and provisions of the 2012 Long-Term Incentive Plan (“2012 Incentive Plan”). The 2012 Incentive Plan was approved by shareholders owning the majority of the Company’s shares of common stock and became effective on May 1, 2012, after which time no new equity awards may be made under the 2012 Incentive Plan. The Company has reserved 5,000,000 shares of common stock for issuance upon grant or exercise of awards by participants under the 2012 Incentive Plan. These shares have not been registered with the SEC. The 2012 Incentive Plan provided shares available for restricted stock or options granted to employees, directors, and others. Stock options granted under the 2012 Incentive Plan generally vest over one to five years or as otherwise determined by the Board or committee of the Board. Options to purchase shares of common stock expire no later than ten years after the date of grant.

In addition, the number of shares of Common Stock subject to the 2012 Incentive Plan, any number of shares subject to any numerical limit in the 2012 Plan, and the number of shares and terms of any incentive award are expected to be adjusted in the event of any change in our outstanding Common Stock by reason of any stock dividend, spin-off, split-up, stock split, reverse stock split, recapitalization, reclassification, merger, consolidation, liquidation, business combination or exchange of shares or similar transaction.

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Administration

It is expected that the Compensation Committee of the Board of Directors, or the Board of Directors in the absence of such a committee, will administer the 2012 Incentive Plan. Subject to the terms of the 2012 Incentive Plan, the Compensation Committee would have complete authority and discretion to determine the terms of awards under the 2012 Incentive Plan.

Grants

The 2012 Incentive Plan authorizes the grant to participants of nonqualified stock options, incentive stock options, restricted stock awards, restricted stock units, performance grants intended to comply with Section 162(m) of the Internal Revenue Code (as amended, the "Code") and stock appreciation rights, as described below:

- Options granted under the 2012 Incentive Plan entitle the grantee, upon exercise, to purchase a specified number of shares from us at a specified exercise price per share. The exercise price for shares of Common Stock covered by an option cannot be less than the fair market value of the Common Stock on the date of grant unless agreed to otherwise at the time of the grant.
- Restricted stock awards and restricted stock units may be awarded on terms and conditions established by the compensation committee, which may include performance conditions for restricted stock awards and the lapse of restrictions on the achievement of one or more performance goals for restricted stock units.
- The compensation committee may make performance grants, each of which will contain performance goals for the award, including the performance criteria, the target and maximum amounts payable, and other terms and conditions.
- The 2012 Incentive Plan authorizes the granting of stock awards. The compensation committee will establish the number of shares of Common Stock to be awarded and the terms applicable to each award, including performance restrictions.
- Stock appreciation rights ("SARs") entitle the participant to receive a distribution in an amount not to exceed the number of shares of Common Stock subject to the portion of the SAR exercised multiplied by the difference between the market price of a share of Common Stock on the date of exercise of the SAR and the market price of a share of Common Stock on the date of grant of the SAR.

Duration, Amendment and Termination

The Board has the power to amend, suspend or terminate the 2012 Incentive Plan without stockholder approval or ratification at any time or from time to time. No change may be made that increases the total number of shares of Common Stock reserved for issuance pursuant to incentive awards or reduces the minimum exercise price for options or exchange of options for other incentive awards, unless such change is authorized by our stockholders within one year. Unless sooner terminated, the 2012 Incentive Plan would terminate ten years after it is adopted.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Other than as disclosed below and in this Annual Report, there have been no transactions, since January 1, 2013, or any currently proposed transaction, in which we were or are to be a participant and the amount involved exceeds the lesser of $120,000 or 1% of the average of our total assets at year end for the last two completed fiscal years and in which any of our directors, executive officers or beneficial holders of more than 5% of our outstanding common stock, or any of their respective immediate family members, has had or will have any direct or material indirect interest.

Employment Agreements

On April 1, 2013, the Company entered into an employment agreement with Mr. Griffin as its Chief Executive Officer. The employment agreement provides for (i) an annual base salary of $210,000 per year, subject to annual increase at the Board of Directors' discretion. If Mr. Griffin's employment is terminated without Cause during the first year of the agreement, or if he resigns for Good Reason (as defined in his agreement), he will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which he was a participant immediately prior to his last date of employment with the Company for a period of six months following such cessation of employment. If such a termination should occur during the second year of the agreement or thereafter, the severance period is reduced to three months The term of the employment agreement is for a period of two years and automatically renews for successive one year periods thereafter unless terminated pursuant to the agreement. Prior to April 1, 2013, Mr. Griffin's compensation was governed by an employment agreement with Mesa. Under the terms of that agreement, Mr. Griffin was entitled to an annual base salary of $180,000 in 2012. Mr. Griffin offered forbearance to the Company for payment of his salary for the period September 1, 2009 through July 31, 2011. Beginning January 1, 2012, the Company made monthly payments of $10,000 to Mr. Griffin until the accrued salary was repaid to him in full in 2013.

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On September 19, 2011, Mesa entered into an employment agreement with Rachel L. Dillard, its Chief Financial Officer, which agreement was assumed by Armada upon the closing of the Mesa Acquisition. The employment agreement, as amended, provides for an annual base salary of $134,375. If Ms. Dillard's employment is terminated without Cause, or if she resigns for Good Reason (as defined in her agreement), she will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which she was a participant immediately prior to her last date of employment with the Company for a period of three months following such cessation of employment. The original term of the employment agreement was for a period of twelve months and it automatically renews for one year periods thereafter unless terminated pursuant to the agreement. Any unvested equity compensation vests upon Ms. Dillard's death or disability. Under the employment agreement with Mesa, Ms. Dillard received restricted stock awards totaling 1,200,000 shares. 600,000 of those restricted shares were vested as of the date of the Mesa Acquisition and were exchanged for 240,000 shares of Armada common stock. The remaining 600,000 shares under the Mesa restricted shares awards were converted in March 2013 to Mesa incentive stock options which were assumed by Armada upon the closing of the Mesa Acquisition. Under this assumption, Ms. Dillard received options to purchase 240,000 shares of Armada common stock exercisable at a price of $0.33 per share and expiring on March 20, 2018.

On April 1, 2013, the Company entered into an employment agreement with James J. Cerna, Jr., its President. The employment agreement provides for (i) an annual base salary of $144,000, subject to annual increase at the Board of Directors' discretion. If Mr. Cerna's employment is terminated without Cause, or if he resigns for Good Reason (as defined in his agreement), he will be entitled to any earned but unpaid base salary and unpaid pro rata annual bonus and continued coverage, at the Company's expense, under all benefits plans in which he was a participant immediately prior to his last date of employment with the Company for a period of six months following such cessation of employment. If such a termination should occur during the second year of the agreement or thereafter, the severance period is reduced to three months. The term of the employment agreement is for a period of two years and automatically renews for successive one year periods thereafter unless terminated pursuant to the agreement. Prior to April 1, 2013, Mr. Cerna received an annual salary of $180,000 plus reimbursement for health benefits.

While the Company does not have a written employment agreement with J. Clint Unruh, we have agreed to pay Mr. Unruh an annual salary of $120,000.

Option Grants

On March 20, 2013, Mesa converted the unvested 600,000 share portion of two restricted stock grants to Rachel L. Dillard, our Chief Financial Officer, into an incentive stock option to purchase 600,000 shares of Mesa's common stock at an exercise price of $0.33 per share. On March 28, 2013, upon the closing of the Mesa Acquisition, this stock option was converted into an Armada stock option to purchase 240,000 shares of our common stock. This option has an exercise price of $0.33 per share and expires on March 30, 2018.

On April 19, 2013 we issued to Randy M. Griffin, our Chief Executive Officer, an incentive stock option to purchase 500,000 shares of our common stock under our 2012 Incentive Plan. This option has an exercise price of $0.40 per share, became fully vested on date of grant and expires on April 1, 2018.

On April 19, 2013, we issued to James J. Cerna, Jr., our President, an incentive stock option to purchase 500,000 shares of our common stock under our 2012 Incentive Plan. This option has an exercise price of $0.40 per share, vested on date of grant, and expires on April 1, 2018. On December 31, 2013, we cancelled a previously granted option to Mr. Cerma for the purchase of 100,000 shares of our common stock at an exercise price of $0.63, which would have expired on January 5, 2015, and replaced it with an incentive stock option to purchase 150,000 shares of our common stock at an exercise price of $0.40. This option expires on December 31, 2017.

Other Relationships

Marceau Schlumberger, one of our directors, is a founder and managing member of Coral Reef Capital, LLC (“Coral Reef”). Mr. Schlumberger, along with the other partners of Coral Reef, shares responsibility for all major management and operational functions of that firm. Mr. Schlumberger is also the managing member of Gulfstar Manager LLC which is the manager of Gulfstar Resources, LLC, and he owns a 3% interest in Gulfstar.

As a result of the closing of Tranche A of the Gulfstar Transaction in which Gulfstar purchased $6,250,000 in membership interests in TNRH, Gulfstar owns a 34.375% interest in TNRH. Following the closing, Gulfstar appointed Mr. Schlumberger as its designated member of the management committee of TNRH. Because of his relationships with Coral Reef and Gulfstar, Mr. Schlumberger abstained from our Board of Directors’ vote on the Gulfstar Transaction.

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At the closing of Tranche A, TNRH entered into a Consulting Services Agreement with Coral Reef pursuant to which, until the date on which Gulfstar disposes of all of its debt and equity interests in TNRH, or the earlier termination of the Consulting Services Agreement due to specified defaults by Coral Reef, Coral Reef will provide certain consulting services to TNRH. TNRH will pay Coral Reef an amount per year equal to 3% of the aggregate amount of capital contributions, debt investments and equity investments made by Coral Reef or its affiliates (including Gulfstar) to or in TNRH or the Company. Coral Reef is also entitled to reimbursement for all reasonable out-of-pocket expenses incurred in connection with the proper performance of the consulting services. For the fiscal year ended December 31, 2013, we paid Coral Reef $187,500 under the Consulting Services Agreement.

Director Independence

Our Board of Directors has considered the independence of its directors in reference to the definition of "independent director" established by the NASDAQ Marketplace Rule 5605(a)(2). In doing so, the Board has reviewed all commercial and other relationships of each director in making its determination as to the independence of its directors. After such review, the Board has determined that each of Messrs. Wold, Hern, Schlumberger, and Zaziski qualifies as independent under the requirements of the NASDAQ listing standards.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit Fees

The aggregate fees billed to us by our principal accountant for services rendered during the fiscal years ended December 31, 2013 and 2012 are set forth in the table below:

Fee Category	2013	2012
Audit fees (1)	$ 200,000	$ 195,000
Audit-related fees (2)	—	30,650
Tax fees (3)	—	—
All other fees (4)	—	—
Total fees	$ 200,000	$ 225,650

(1) Audit fees consist of fees incurred for professional services rendered for the audit of consolidated financial statements, for reviews of our interim consolidated financial statements included in our quarterly reports on Forms 10-Q and for services that are normally provided in connection with statutory or regulatory filings or engagements.

(2) Audit-related fees consist of fees billed for professional services that are reasonably related to the performance of the audit or review of our consolidated financial statements, but are not reported under "Audit fees."

(3) Tax fees consist of fees billed for professional services relating to tax compliance, tax planning, and tax advice.

(4) All other fees consist of fees billed for all other services.

Audit Committee's Pre-Approval Policies and Procedures

Our Board of Directors includes an audit committee which is directly responsible for the appointment, compensation, retention and oversight of the work of any registered public accounting firm engaged by us for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for us, and each such registered public accounting firm must report directly to the Board. It is our audit committee's policy to approve in advance all audit, review and attest services and all non-audit services (including, in each case, the engagement fees there for and terms thereof) to be performed by our independent auditors, in accordance with applicable laws, rules and regulations.

Our audit committee selected GBH CPAs, PC as our independent registered public accounting firm for purposes of auditing our financial statements for the year ended December 31, 2013. In accordance with Board's practice, GBH CPAs, PC was pre-approved by the Board to perform these audit services for us prior to its engagement.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Exhibits

Exhibit No.	SEC Report Reference No.	Description
2.1	2.1	Asset Purchase Agreement and Plan of Reorganization, dated as of November 14, 2012, among Armada Oil, Inc., Mesa Energy Holdings, Inc., and Mesa Energy Inc. (included as Appendix A) (1)
2.2	2.2	Amendment No. 1 to the Asset Purchase Agreement & Plan of Reorganization, dated as of February 19, 2013, among Armada Oil, Inc., Mesa Energy Holdings, Inc. & Mesa Energy, Inc. (2)
2.3	2.2	Agreement and Plan of Merger and Reorganization, dated as of August 31, 2009, by and among Mesa Energy Holdings, Inc., Mesa Energy Acquisition Corp. and Mesa Energy, Inc. (3)
3.1	3.1	Armada Oil, Inc., Articles of Incorporation. (3)
3.2	3.1	Armada Oil, Inc., Articles of Incorporation, as amended. (3)
3.3	3.3	Armada Oil, Inc., Articles of Incorporation, as amended. (3)
3.4	3.1	Amended and Restated By-Laws of Armada Oil, Inc. (4)
4.1	4.5	Form of Series A Common Stock Purchase Warrant (3)
4.2	4.6	Form of Series B Common Stock Purchase Warrant (3)
4.3	4.7	Form of Series C Common Stock Purchase Warrant (3)
4.4	4.1	Form of Armada Oil, Inc. Series A Senior Unsecured 9.625% Note (5)
4.5	4.2	Form of Series D Common Stock Purchase Warrant (5)
4.6	10.2	Form of revised Series D Warrant of Armada Oil, Inc.(6)
10.1	10.1	Voting Agreement, dated as of November 14, 2012, among Armada Oil, Inc. and the signatories thereto (included as Appendix C)(1)
10.2	*	Assignment and Assumption Agreement dated as of March 28, 2013, between Mesa Energy Holdings, Inc., and Mesa Energy Inc.
10.3	10.10	

		Spring Valley Center Office Lease, dated June 1, 2007, between Spring Valley Center, LLP and Mesa Energy, Inc. (3)
10.4	10.11	First Modification to Office Lease, dated February 28, 2012, between Spring Valley Center, LLP and Mesa Energy, Inc. (3)
10.5	10.21	Letter Agreement, dated March 17, 2009, between Mesa Energy, Inc. and Robert Thomasson (3)
10.6	10.22	Purchase and Sale Agreement, dated June 17, 2009, between Hydrocarbon Generation, Inc. and Sycamore Resources, Inc. (3)
10.7	10.23	Assignment of Purchase and Sale Agreement, dated as of August 25, 2009, from Sycamore Resources, Inc. to Mesa Energy, Inc. (3)
10.8	10.17	Membership Interest Purchase Agreement, dated as of June 1, 2011, by and among Mesa Energy Holdings, Inc., Mesa Energy, Inc., Tchefuncte Natural Resources, LLC and its Members (3)
10.9	10.18	Employment Services Agreement dated September 19, 2011, between Mesa Energy Holdings, Inc. and Rachel L. Dillard (3)

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10.10	10.19	Amendment dated October 17, 2011 Employment Services Agreement dated September 19, 2011, between Mesa Energy Holdings, Inc. and Rachel L. Dillard (3)
10.11	10.20	Amendment dated October 1, 2012, to Employment Services Agreement dated September 19, 2011, between Mesa Energy Holdings, Inc. and Rachel L. Dillard (3)
10.12	10.22	Loan Agreement, dated July 22, 2011, by and among Mesa Energy, Inc., Mesa Energy Holdings, Inc., TNR Natural Resources, LLC, Mesa Gulf Coast, LL C and The F&M Bank & Trust Company (3)
10.13	10.23	Security Agreement dated July 22, 2011 by TNR Natural Resources, LLC for the benefit of F&M Bank & Trust Company (3)
10.14	10.24	Mortgage, Collateral Assignment, Security Agreement and Financing Statement, dated July 22, 2011 by TNR Natural Resources, LLC for the benefit of F&M Bank & Trust Company (3)
10.15	10.25	Pledge and Security Agreement dated July 22, 2011 by Mesa Energy, Inc. for the benefit of F&M Bank & Trust Company (3)
10.16	10.26	Unlimited Guaranty dated July 22, 2011, by Mesa Energy Holdings, Inc. for the benefit of F&M Bank & Trust Company (3)
10.17	10.27	Unlimited Guaranty dated July 22, 2011, by Mesa Gulf Coast, LLC for the benefit of F&M Bank & Trust Company (3)
10.18	10.28	Unlimited Guaranty dated July 22, 2011, by Tchefuncte Natural Resources, LLC for the benefit of F&M Bank & Trust Company (3)
10.19	10.33	Purchase and Option Agreement between TR Energy, Inc. and Armada Oil, Inc., dated February 7, 2012 (3)
10.20	10.34	Share Exchange Agreement dated March 21, 2012, between NDB Energy, Inc., Armada Oil, Inc. and the Armada Stockholders (3)
10.21	10.37	Amendment and Extension to the Purchase and Option Agreement dated February 7, 2012, between TR Energy, Inc. and Armada Oil, Inc. (3)
10.22	10.38	Seismic and Farmout Option Contract between Anadarko E&P Company LP, Anadarko Land Corp. and Armada Oil, Inc., dated October 22, 2012 (3)
10.23	10.40	Amendment and Extension to the Purchase and Option Agreement dated February 7, 2012, between TR Energy, Inc. and Armada Oil, Inc., dated January 10, 2013 (7)
10.24	10.41	Amendment and Extension to the Purchase and Option Agreement dated February 7, 2012, between TR Energy, Inc. and Armada Oil, Inc. dated March 5, 20 (8)
10.25	10.1	Form of Securities Purchase Agreement between Armada Oil, Inc. and certain investors (5)
10.26	10.2	Form of Armada Oil, Inc. Nonstatutory Stock Option Agreement (5)

10.27	10.2	Form of Unlimited Guarantee dated March 28, 2013 by Armada Oil, Inc. for the benefit of F&M Bank & Trust Company, for itself and as Collateral Agent (3)
10.28	10.1	Executive Employment Agreement dated as of April 1, 2013, between Armada Oil, Inc., and Randy M. Griffin (9)
10.29	10.2	Executive Employment Agreement dated as of April 1, 2013, between Armada Oil, Inc., and James J. Cerna, Jr. (9)
10.30	10.3	Form of Stock Option Agreement with directors and executive officers under the Company's 2012 Long-Term Incentive Plan (9)
10.31	10.1	Form of Offering Modification Agreement between Armada Oil, Inc. and purchasers of the 2012 Units (6)

10.32	10.1	Third Amendment to the Seismic and Farmout Option Contract between the Registrant and Anadarko E&P Onshore LLC (10)
10.33	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 (11)
10.34	10.2	Agreement to sell properties in Young County, Texas dated October 1, 2013 by and between the Registrant and Energy Management Resources, LLC (11)
10.35	10.1	Unit Purchase Agreement, dated as of December 20, 2013, among TNR Holdings LLC, Mesa Energy, Inc., the Company and Gulfstar Resources LLC (12)
10.36	10.2	Amended and Restated Limited Liability Company Agreement of TNR Holdings LLC, dated as of December 20, 2013, between Mesa Energy, Inc., and Gulfstar Resources LLC (12)
10.37	10.3	Consulting Services Agreement, dated as of December 20, 2013, between Coral Reef Capital LLC and TNR Holdings LLC (12)
10.38	10.4	Transition Services Agreement, dated as of December 20, 2013, between Mesa Energy, Inc., and TNR Holdings LLC (12)
10.39	10.5	Fourth Amendment to Loan Agreement between Mesa Energy, Inc., and The F&M Bank & Trust Company (12)
10.40	10.6	Unlimited Guaranty dated December 19, 2013, by TNR Holdings, LLC, for the benefit of The F&M Bank & Trust Company (12)
10.41	10.1	Agreement for Purchase and Sale dated as of March 13, 2014, by and between Piqua Petro, Inc., and Armada Midcontinent, LLC, or its assigns (13)
14.1	14.1	Code of Business Conduct and Ethics (2)
16.1	16.1	Letter regarding change in certifying accountants dated October 15, 2012 (2)
21	*	List of Subsidiaries
31.1	*	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
31.2	*	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
32.1	*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
32.2	*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

99.1	*	Letter from Ralph E. Davis Associates, Inc. to Armada Oil, Inc. dated February 21, 2014 relating to its reserves estimates dated as of December 31, 2013
101 INS		XBRL Instance Document***
101 SCH		XBRL Schema Document***
101 CAL		XBRL Calculation Linkbase Document***
101 DEF		XBRL Definition Linkbase Document***
101 LAB		XBRL Labels Linkbase Document***
101 PRE		XBRL Presentation Linkbase Document***

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* Filed/furnished 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.

***The XBRL related information in Exhibit 101 shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability of that section and shall not be incorporated by reference into any filing or other document pursuant to the Securities Act, except as shall be expressly set forth by specific reference in such filing or document.

(1) Filed with the Securities and Exchange Commission (the “SEC”) on November 29, 2012 as an Appendix to the proxy statement/prospectus forming part of the Registrant’s Registration on Form S-4, which appendix is incorporated herein by reference.

(2) Filed with the SEC on February 22, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated February 19, 2013, which exhibit is incorporated herein by reference.

(3) Filed with the SEC on December 11, 2012, as an exhibit, numbered as indicated above, to the Registrant’s Registration Statement on Form S-4, Amendment #1, which exhibit is incorporated herein by reference.

(4) Filed with the SEC on March 29, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated March 28, 2013, which exhibit is incorporated herein by reference.

(5) Filed with the SEC on March 28, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated March 20, 2013, which exhibit is incorporated herein by reference.

(6) Filed with the SEC on April 30, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated April 26, 2013, which exhibit is incorporated herein by reference.

(7) Filed with the SEC on December 11, 2012, as an exhibit, numbered as indicated above, to the Registrant’s Registration Statement on Form S-4, Amendment #2, which exhibit is incorporated herein by reference.

(8) Filed with the SEC on December 11, 2012, as an exhibit, numbered as indicated above, to the Registrant’s Registration Statement on Form S-4, Amendment #3, which exhibit is incorporated herein by reference.

(9) Filed with the SEC on April 25, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated April 19, 2013, which exhibit is incorporated herein by reference

(10) Filed with the SEC on November 6, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated October 31, 2013, which exhibit is incorporated herein by reference

(11) Filed with the SEC on November 14, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Quarterly Report on Form 10-Q, for the period ended September 30, 2013, which exhibit is incorporated herein by reference

(12) Filed with the SEC on December 27, 2013, as an exhibit, numbered as indicated above, to the Registrant’s Current Report on Form 8-K, dated December 20, 2013, which exhibit is incorporated herein by reference

(13) Filed with the SEC on March 20, 2014, as an exhibit, numbered as indicated above, to the Registrant's Current Report on Form 8-K, dated March 14, 2014, which exhibit is incorporated herein by reference

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ARMADA OIL, INC.

Dated: March 31, 2014	By:	/s/ RANDY M. GRIFFIN Randy M. Griffin, Chief Executive Officer
Dated: March 31, 2014	By:	/s/ RACHEL L. DILLARD Rachel L. Dillard, Chief Financial Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	DATE
/s/ RANDY M. GRIFFIN Randy M. Griffin	Chairman of the Board and Chief Executive Officer (principal executive officer)	March 31, 2014
/s/ JAMES J. CERNA, JR. James J. Cerna, Jr.	Director, President	March 31, 2014
/s/ RAY L. UNRUH Ray L. Unruh	Director	March 31, 2014
/s/ KENNETH T. HERN Kenneth T. Hern	Director	March 31, 2014
/s/ FRED B. ZAZISKI Fred B. Zaziski	Director	March 31, 2014
/s/ MARCEAU N. SCHLUMBERGER Marceau N. Schlumberger	Director	March 31, 2014
/s/ ERIC WOLD Eric Wold	Director	March 31, 2014

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ARMADA OIL, INC.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
Armada Oil, Inc.
Dallas, Texas

We have audited the accompanying consolidated balance sheets of Armada Oil, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of operations, changes in equity and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects the consolidated financial position of Armada Oil, Inc. as of December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ GBH CPAs, PC

GBH CPAs, PC
www.gbhcpas.com
Houston, Texas
March 31, 2014

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ARMADA OIL, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,095,972	$ 5,884,649
Accounts receivable – oil and gas	1,524,623	1,593,258
Accounts receivable – other	32,538	280,430
Derivative assets, commodity contracts – current	—	83,298
Deferred financing costs, net – current	13,162	22,563
Deferred tax assets – current	100,606	38,325
Prepaid expenses	202,280	117,678
TOTAL CURRENT ASSETS	8,969,181	8,020,201
Oil and gas properties, successful efforts accounting:		
Properties subject to amortization, net	7,692,703	9,082,526
Properties not subject to amortization	10,653,825	759,133
Support facilities and equipment, net	2,417,898	2,075,563
Land	38,345	48,345
Net oil and gas properties	20,802,771	11,965,567
Property and equipment, net	242,676	241,627
Deferred financing costs, net – noncurrent	—	13,162
Deferred tax asset – noncurrent	5,502,988	3,126,478
Deposits on asset retirement obligations	585,973	609,421
Production payment receivable	131,250	—
Other assets	55,598	4,013
TOTAL ASSETS	$ 36,290,437	$ 23,980,469
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 1,362,867	$ 1,045,918
Revenue payable	418,213	334,433
Accrued expenses	444,972	753,961
Accrued expenses – related parties	70	54,840
Notes payable, net – current	8,767,392	90,417
Notes payable – related parties, net – current	102,158	—
Derivative liability, commodity contracts – current	173,806	—
Other current liabilities	10,000	91,000
TOTAL CURRENT LIABILITIES	11,279,478	2,370,569
Notes payable, net – noncurrent	—	9,195,963
Derivative liability – commodity contracts – noncurrent	53,289	58,519
Deferred tax liability – noncurrent	3,703,553	678,782
Asset retirement obligations	3,161,810	3,507,798
TOTAL LIABILITIES	18,198,130	15,811,631

Commitments and contingencies				
Equity:				
Preferred stock, par value $0.01, 1,000,000 shares authorized, 0 shares issued and outstanding		—		—
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		16,108,722		803,974
Retained earnings (deficit)		(4,038,633)		7,331,132
Total equity attributable to Armada Oil, Inc.		12,126,119		8,168,838
Noncontrolling interest		5,966,188		—
TOTAL EQUITY		18,092,307		8,168,838
TOTAL LIABILITIES AND EQUITY	$	36,290,437	$	23,980,469

See accompanying notes to consolidated financial statements.

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ARMADA OIL, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2013	2012
Revenues	$ 12,436,210	$ 14,865,169
Operating expense:		
Lease operating expense	7,470,967	7,062,611
Environmental remediation expense	—	244,237
Exploration expense	284,275	115,276
Dry hole expense	2,591,770	—
Depletion, depreciation, amortization, accretion and impairment expense	1,231,340	1,832,537
(Gain) loss on settlement of asset retirement obligations	(3,428)	116,394
Loss on sale of oil and gas properties	86,116	—
Impairment of goodwill	8,536,758	—
General and administrative expense	4,469,260	3,636,010
Total operating expense	24,667,058	13,007,065
Income (loss) from operations	(12,230,848)	1,858,104
Other income (expense):		
Interest income	4,412	8,602
Interest expense	(822,335)	(503,638)
Realized gain on commodity contracts	216,100	440,699
Unrealized loss on change in derivatives – commodity contracts	(251,876)	(912,963)
Loss on change in derivative values – convertible debt	—	(534,989)
Loss on modification of offering	(65,749)	—
Other income (expense)	14,391	(7,261)
Total other expense	(905,057)	(1,509,550)
Income (loss) before income taxes	(13,135,905)	348,554
Income tax benefit (expense)	1,766,140	(489,265)
Net loss	(11,369,765)	(140,711)
Net loss attributable to noncontrolling interest	—	—
Net loss attributable to Armada Oil, Inc.	$ (11,369,765)	$ (140,711)
Net loss per common share:		
Basic	$ (0.22)	$ (0.00)
Diluted	$ (0.22)	$ (0.00)
Weighted average number of common shares outstanding:		
Basic	50,751,878	33,484,800
Diluted	50,751,878	33,484,800

See accompanying notes to consolidated financial statements.

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ARMADA OIL, INC.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
For the Years Ended December 31, 2013 and 2012

	Common Stock Shares	Common Stock Par	Additional Paid-In Capital	Retained Earnings (Deficit)	Noncontrolling Interest	Total
Balances at December 31, 2011	79,531,324	$ 7,953	$ (633,745)	$ 7,471,843	$ —	$ 6,846,051
Share-based compensation	1,071,000	107	303,876	—	—	303,983
Conversion of notes payable and accrued interest to stock	3,728,153	373	465,646	—	—	466,019
Transfer of derivative liability from liability classification to equity classification	—	—	648,072	—	—	648,072
Warrant expense	—	—	45,424	—	—	45,424
Net loss	—	—	—	(140,711)	—	(140,711)
Balances at December 31, 2012	84,330,477	8,433	829,273	7,331,132	—	8,168,838
Common stock issued for Armada acquisition	21,094,633	21,095	14,035,247	—	—	14,056,342
Acquisition adjustment – shares	(50,598,286)	(50,598)	50,598	—	—	—
Acquisition adjustment – par value		75,897	(75,897)	—	—	—
Share-based compensation	183,000	183	737,639	—	—	737,822
Shares issued for stock payable	380,651	380	324,619	—	—	325,000
Issuance of common stock for	639,998	640	65,109	—	—	65,749

modification of debt offering						
Issuance of warrants as debt discount with debt offering	—	—	142,133	—	—	142,133
Issuance of equity in subsidiary to settle note payable	—	—	—	—	600,000	600,000
Sale of noncontrolling interest in subsidiary	—	—	—	—	5,366,188	5,366,188
Net loss	—	—	—	(11,369,765)	—	(11,369,765)
Balances at December 31, 2013	56,030,473	$ 56,030	$ 16,108,722	$ (4,038,633)	$ 5,966,188	$ 18,092,307

See accompanying notes to consolidated financial statements.

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ARMADA OIL, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013 and 2012

	Year Ended December 31, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (11,369,765)	$ (140,711)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization, accretion and impairment	1,231,340	1,832,537
Impairment of goodwill	8,536,758	—
Dry hole expense	2,591,770	—
Deferred income taxes	(1,766,140)	389,938
Share-based compensation	737,822	349,407
Loss on sale of oil and gas properties	86,116	—
(Gain) loss on settlement of asset retirement obligations	(3,428)	116,394
Amortization of debt discount charged to interest expense	161,201	4,279
Amortization of deferred financing costs	56,292	44,213
Realized gain on derivative commodity contracts	(216,100)	(440,699)
Unrealized loss on change in derivatives – commodity contracts	251,876	912,963
Gain on change in derivative values – convertible debt	—	534,989
Loss on offering modification	65,749	—
Changes in operating assets and liabilities:		
Accounts receivable – oil and gas	68,635	867,002
Accounts receivable – other	247,892	(221,612)
Prepaid expenses	161,854	(24,076)
Accounts payable and accrued expenses	(387,206)	(638,919)
Accrued expenses – related parties	(54,770)	—
Revenue payable	83,780	(461,788)
CASH PROVIDED BY OPERATING ACTIVITIES	483,676	3,123,917
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid for acquisition and development of oil and gas properties	(2,689,064)	(3,795,819)
Cash received from sale of oil and gas properties	85,000	—
Cash paid for support facilities and equipment	(241,821)	(277,813)
Cash received from sale of support facilities and equipment	54,018	—
Cash paid to settle asset retirement obligations for oil and gas properties	—	(225,172)
Cash proceeds from settlement of derivative commodity contracts	216,100	440,699
Cash paid for acquisition of Armada	(293,106)	—
Cash paid for property and equipment	(10,163)	(86,132)
Cash received for refund of deposit on asset retirement obligation	23,448	—
CASH USED IN INVESTING ACTIVITIES	(2,855,588)	(3,944,237)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from borrowings on line of credit, net of financing costs	—	4,000,000
Proceeds from borrowings on debt, net of financing costs	786,271	79,419
Proceeds from borrowings on debt – related party	135,000	—
Principal payments on notes payable	(2,583,224)	(511,342)
Installment payments on software	(121,000)	(45,500)
	5,366,188	—

Cash received from sale of noncontrolling interest in subsidiary, net of placement costs				
CASH PROVIDED BY FINANCING ACTIVITIES		3,583,235		3,522,577
NET CHANGE IN CASH		1,211,323		2,702,257
CASH AT BEGINNING OF YEAR		5,884,649		3,182,392
CASH AT END OF YEAR	$	7,095,972	$	5,884,649
SUPPLEMENTAL DISCLOSURES OF CASH FLOWS INFORMATION				
Cash paid for interest	$	695,288	$	479,494
Cash paid for income taxes	$	75,000	$	77,000
NON-CASH INVESTING AND FINANCING TRANSACTIONS				
Insurance financed with notes payable	$	214,980	$	89,631
Software purchased with installment payments	$	40,000	$	136,500
Oil and gas property sold for production payment receivable	$	131,250	$	—
Change in accrued oil and gas development costs	$	(65,692)	$	—
Note payable issued to settle account payable	$	1,384,139	$	—
Issuance of equity in subsidiary to settle note payable	$	600,000	$	—
Transfer of derivative liability from liability classification to equity classification	$	—	$	648,072
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	$	—
Change in asset retirement obligations	$	(559,227)	$	—
Common stock issued and options and warrants assumed for Armada acquisition	$	14,056,342	$	—

See accompanying notes to consolidated financial statements.

ARMADA OIL, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

The consolidated financial statements include the accounts of the Company. and its wholly-owned subsidiaries, Armada Oil and Gas, Inc. ("AOG"), Armada Operating, LLC ("AOP"), Mesa Energy, Inc. ("MEI"), Mesa Gulf Coast, LLC ("MGC"), Tchefuncte Natural Resources, LLC ("TNR"), Mesa Midcontinent LLC ("MMC"), Armada Midcontinent, LLC, formerly known as MMC Resources, LLC ("AMC"), and TNR Holdings, LLC ("TNRH") (the Company owns 65.625% of this subsidiary).

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 four 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 and Principles of Consolidation

The consolidated financial statements herein have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and include the accounts of the Company and those of its wholly owned and majority 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 we believe 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.

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.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less.

Accounts Receivable

Accounts receivable are stated at the historical carrying amount net of writeoffs and allowance for uncollectible accounts. The carrying amount of the Company's accounts receivable approximates fair value because of the short-term nature of the instruments.

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The Company routinely assesses the collectibility of all material trade and other receivables. The Company's oil and gas receivables primarily comprise receivables from purchasers of the Company's oil and gas and from joint interest owners on properties the Company operates. The Company may have the ability to withhold future revenue disbursements to recover any nonpayment of these joint interest billings. Joint interest receivables are recorded when the Company incurs expenses on behalf of the non-operator interest owners in the properties the Company operates.

The Company's reported balance of accounts receivable, net of allowance for doubtful accounts, represents management's estimate of the amount that ultimately will be realized in cash. The Company reviews the adequacy of the allowance for doubtful accounts on an ongoing basis, using historical payment trends, the age of the receivables and knowledge of the individual customers or joint interest owners. When the analysis indicates, management increases or decreases the allowance accordingly. However, if the financial condition of our customers were to deteriorate, additional allowances might be required.

Deferred Financing Costs

The costs of issuing debt are capitalized. These costs are amortized over the expected life of the related instrument. When a security is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed.

Oil and Gas Properties, Successful Efforts Method

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under the successful efforts method, costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred.

The cost of oil and gas properties is amortized at the well level based on the unit of production method. Unit of production rates are based on oil and gas reserves and developed producing reserves estimated to be recoverable from existing facilities based on the current terms of the respective production agreements. The Company’s reserve estimates represent crude oil and natural gas which management believes can be reasonably produced within the current terms of their production agreements.

The Company evaluates its proved oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset’s carrying value may not be recoverable. The Company follows Accounting Standards Codification ASC 360 - Property, Plant, and Equipment, for these evaluations. Unamortized capital costs are reduced to fair value if the undiscounted future net cash flows from our interest in the property’s estimated proved reserves are less than the asset’s net book value.

Support Facilities and Equipment

Our support facilities and equipment are generally located in proximity to certain of our principal fields. Depreciation of these support facilities is provided on the straight-line method based on estimated useful lives of 7 to 20 years.

Maintenance and repair costs that do not extend the useful lives of property and equipment are charged to expense as incurred.

Proved Reserves

Estimates of the Company's proved reserves included in this report are prepared in accordance with GAAP and guidelines from the United States Securities and Exchange Commission ("SEC"). The Company's engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and impairment. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserves estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions, and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of the Company's estimated proved reserves. The Company engages independent reserve engineers to estimate its proved reserves.

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Fair Value of Financial Instruments

The Company adopted the framework for measuring fair value that establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instruments, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). The Company's valuation models are primarily industry standard models. Level 3 instruments include derivative warrant instruments. The Company does not have sufficient corroborating evidence to support classifying these assets and liabilities as Level 1 or Level 2.

The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of the derivative warrant instruments was calculated using a modified lattice valuation model.

The following table sets 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 December 31, 2013 and 2012:

	Carrying Value at December 31, 2013	Fair Value Measurement at December 31, 2013		
		Level 1	Level 2	Level 3
Derivative assets, commodity contracts	$ —	$ —	$ —	$ —
Derivative liabilities, commodity contracts	(227,095)	—	(227,095)	—

	Carrying Value at December 31, 2012	Fair Value Measurement at December 31, 2012		
		Level 1	Level 2	Level 3
Derivative assets, commodity contracts	$ 83,298	$—	$83,298	$—
Derivative liabilities, 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.

The Company does not apply hedge accounting, as our hedging program is designed only to comply with covenants underlying our credit facility with F&M Bank and not as a formal risk management program, and we do not monitor the effectiveness of the hedge. Realized gains and losses (i.e., cash settlements) are reported in our consolidated statement of operations. Similarly, changes in the fair value of unsettled derivative instruments are recorded as unrealized gains or losses in the Statement of Operations.

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Asset Retirement Obligations

The Company follows the provisions of the Accounting Standards Codification ASC 410 - Asset Retirement and Environmental Obligations. The fair value of an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the long-lived asset. The Company's asset retirement obligations relate to the abandonment of oil and gas producing facilities and facilities that support the production of oil and gas. The amounts recognized are based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. After recording these amounts, the ARO will be accreted to its future estimated value using the same assumed cost of funds and the capitalized costs are depreciated on a unit-of-production basis. Both the accretion and the depreciation will be included in depreciation, depletion and amortization expense on our consolidated statements of operations.

Revenue Recognition

The Company recognizes sales revenues for natural gas, oil, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Share-Based Compensation

The Company follows the Accounting Standards Codification ASC 718 - Compensation - Stock Compensation. Under ASC 718, the Company estimates the fair value of each stock option award at the grant date by using the Black-Scholes option pricing model and common shares based on the last quoted market price of the Company's common stock on the date of the share grant. The fair value determined represents the cost for the award and is recognized over the vesting period during which an employee is required to provide service in exchange for the award. As share-based compensation expense is recognized based on awards ultimately expected to vest, the Company reduces the expense for estimated forfeitures based on historical forfeiture rates. Previously recognized compensation expenses may be adjusted to reflect the actual forfeiture rate for the entire award at the end of the vesting period. Excess tax benefits, as defined in ASC 718, if any, are recognized as an addition to paid-in capital.

Income Taxes

The Company is a taxable entity and recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect when the temporary differences reverse. The effect on the deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the enactment date of the rate change. A valuation allowance is used to reduce deferred tax assets to the amount that is more likely than not to be realized. Interest and penalties associated with income taxes are included in selling, general, and administrative expense.

The Company has adopted ASC 740 "Accounting for Uncertainty in Income Taxes" which prescribes a comprehensive model of how a company should recognize, measure, present, and disclose in its financial statements uncertain tax positions that the company has taken or expects to take on a tax return. ASC 740 states that a tax benefit from an uncertain position may be recognized if it is "more likely than not" that the position is sustainable, based upon its technical merits. The tax benefit of a qualifying position is the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority having full knowledge of all relevant information.

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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 are 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.

	December 31,			
	2013		2012	
Numerator:				
Net loss available to stockholders	$	(11,369,765)	$	(140,711)
Basic net income allocable to participating securities (1)		—		—
Loss available to Armada Oil, Inc.'s stockholders	$	(11,369,765)	$	(140,711)
Denominator:				
Weighted average number of common shares outstanding-Basic		50,751,878		33,484,800
Effect of dilutive securities (2) :				
Options and warrants		—		—
Weighted average number of common shares outstanding-Diluted		50,751,878		33,484,800
Net loss per share:				
Basic	$	(0.22)	$	(0.00)
Diluted	$	(0.22)	$	(0.00)

(1) Restricted share awards that contain non-forfeitable 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 year ended December 31, 2013, "out of the money" stock options representing 2,802,000 shares and warrants representing 7,553,333 shares were antidilutive and, therefore, excluded from the diluted share calculation. For the year ended December 31, 2012, "out of the money" stock options representing 1,010,316 shares and warrants representing 200,000 shares were antidilutive and, therefore, excluded from the diluted share calculation.

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 date the consolidated financial statements were issued for subsequent event disclosure consideration.

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 0.4 common shares of Armada for each Mesa share, or 21,094,633 common shares, valued at $11,602,048, assumed 7,414,787 warrants with a fair value of $1,969,399, assumed 1,064,000 options with a fair value of $484,895, and paid a consultant who worked with the Company in effecting the Acquisition $325,000. The Company also assumed a liability to issue the consultant stock valued at $325,000. This liability was settled with this issuance of 380,651 common shares on April 19, 2013. The total equity instruments issued or assumed in the Acquisition had a fair value of $14,056,342 as of the date of the Acquisition. Total equity and payments resulted in a purchase price of $14,381,342 and the transaction generated goodwill of $8,536,758 which was immediately impaired.

Assumptions used in determining the fair values of the options and warrants noted above were as follows:

Options		
Grant date fair value	$	0.55
Discount rate		0.77%
Expected life (in years)		7.3
Volatility		110.93%
Expected dividends	$	—
Warrants		
Grant date fair value	$	0.55
Weighted average discount rate		0.63%
Weighted average expected life (in years)		4.0
Weighted average volatility		106.70%
Expected dividends	$	—

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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
Total assets acquired	10,577,755
Liabilities assumed:	
Accounts payable and accrued liabilities	2,471,665
Note payable, net of discount of $103,001	197,197
Deferred tax liability	1,999,046
Asset retirement obligations	65,263
Total liabilities assumed	4,733,171
Net assets acquired	5,844,584
Goodwill	8,536,758
Consideration paid – cash and equity instruments at fair value	$ 14,381,342

Since we reported on this matter in our September 30, 2013, Quarterly Report on Form 10-Q, we reassessed the tax basis of the oil and gas properties not subject to amortization. As a result of this reassessment, the deferred tax asset was removed and a deferred tax liability and goodwill were recognized, and the goodwill was impaired. The impairment is reported on the Consolidated Statement of Operations and reflected in the loss from operations.

Pro forma results of operations for the years ended December 31, 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.

	Year Ended December 31,	
	2013	2012
Revenues	$ 12,543,016	$ 14,961,409
Net loss	$ (13,452,350)	$ (2,302,131)
Loss per common share:		
Basic	$ (0.24)	$ (0.04)
Diluted	$ (0.24)	$ (0.04)

Weighted average common shares outstanding		
Basic	55,736,582	55,087,579
Diluted	55,736,582	55,087,579

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NOTE 3 – 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 is also intended 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 closing oil and gas prices, interest rates and volatility factors for the periods under each contract as of December 31, 2013 and 2012.

The details of the commodity derivatives, at December 31, 2013, are summarized below:

Costless Gas Collars

Production Period	Total Volumes	Weighted Average Floor/Ceiling	Fair Value
Jan 2014-Oct 2014 (1)	130,000 MMBtu	$ 3.75 / 4.25	$ (16,940)
Nov 2014-Dec 2014 (1)	26,000 MMBtu	$ 3.75 / 4.50	$ (5,612)

Oil Fixed Price Swaps

Production Period	Total Volumes	Average Fixed Price	Fair Value
Jan 2014-Dec 2014 (1)	60,000 Bbls	$ 95.75	$ (216,665)
Jan 2015-Mar 2015 (1)	11,049 Bbls	$ 92.50	$ (14,570)
Apr 2015-Dec 2015 (2)	31,500 Bbls	$ 89.50	$ (38,718)

Oil Basis Swap

Production Period	Total Volume	Basis Price	Fair Value
Jan 2014-Dec 2014 (3)	60,000 Bbls	$ 4.85	$ 65,312

(1) Costless gas collar and oil fixed price swap entered into on March 8, 2013.
(2) September 30, 2013, fixed oil price swap.
(3)

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.

In addition, 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.

At December 31, 2013, the Company recognized a short-term derivative net liability of $173,806, and a long-term derivative net liability of $53,289, with the change in fair value of $251,876 reflected in unrealized loss on derivative instruments. Realized gains of $216,100 from settlements of commodity derivatives have been reported in other income as realized gain on commodity contracts.

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The details of the commodity derivatives at December 31, 2012, are summarized below:

Costless Gas Collars

Production Period	Total Volumes	Weighted Average Floor/Ceiling	Fair Value
Jan 2013-Dec 2013 (1)	230,000 MMBtu	$ 2.50 / 4.50	$ (24,185)

Gas Fixed Price Swaps

Production Period	Total Volume	Average Fixed Price	Fair Value
Jan 2013-Jul 2013 (2)	70,000 MMBtu	$ 4.00	$ 45,142

Oil Fixed Price Swaps

Production Period	Total Volumes	Average Fixed Price	Fair Value
Jan 2013-Jul 2013 (3)	18,900 Bbls	$ 114.90	$ 161,311

Average Price Oil Collar

Production Period	Total Volume	Average Floor / Ceiling	Fair Value
Jan 2013-Jun 2013 (4)	24,708 Bbls	$ 80 / 100	$ (23,017)
Jul 2013-Dec 2013	40,908 Bbls	$ 80 / 100	$ (75,953)
Jan 2014-Jul 2014	39,424 Bbls	$ 80 / 100	$ (58,519)

(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 December 31, 2012, the Company recognized a short-term derivative asset of $206,453, a short term derivative liability of $123,155, and a long-term derivative liability of $58,519, with the change in fair value of $912,963 reflected in unrealized loss on derivative instruments. Realized gains of $440,699 from settlements of these derivatives have been reported in other income as realized gain on commodity contracts.

NOTE 4 – PROPERTY AND EQUIPMENT

Oil and Gas Properties

The Company's oil and gas properties at December 31, 2013 and 2012 are located in the United States.

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

	December 31,	
Property	2013	2012
Bear Creek Prospect	$ 9,957,839	$ —
Lake Hermitage Field	3,644,986	3,568,957
Valentine Field	1,895,504	1,995,406
Larose Field	1,112,275	1,435,549
Bay Batiste Field	953,197	1,050,390
Turkey Creek Field	782,727	1,791,357
Total	$ 18,346,528	$ 9,841,659

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Net oil and gas properties at December 31, 2013 and 2012 were as follows:

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	10,422,630	2,176,671	(2,591,770)	(346,152)	(1,156,510)	8,504,869
Total	$ 19,270,825	$ 9,537,526	$ (3,057,836)	$ (2,436 535)	$ (4,967,452)	$ 18,346,528

The Company holds oil and gas leasehold interests in Louisiana, Oklahoma, and New York as well as a Seismic and Farmout Option Contract in Wyoming. The Company evaluates each of its properties upon completion of drilling and assessment of reserves to determine which, if any, are subject to impairment.

Additional information about the Company's properties is below:

Lake Hermitage Field – Plaquemines Parish, Louisiana

The Company owns 100% working interests in eighteen wells in the Lake Hermitage Field, of which seven are producing, ten wells are currently shut-in pending evaluation for workover or recompletion and one well is awaiting conversion to a salt water disposal well. During the year ended December 31, 2013, the Company spent $944,856 on development of the Lake Hermitage Field.

Well Name	Amount	Description of work performed
LBLD #3	$42,684	Testing to determine gas potential for new gas line to be constructed in early 2014
LLDSB #3	89,566	Recompletion which continues through early 2014
LLDSB #4	494,064	Recompletion which continues through early 2014
LLDSB #5	12,464	Preparatory work for recompletion to occur in 2014
LLDSB #20	53,841	Recompletion
LLDSB #30	141,610	Recompletion
LLDSB #33	26,506	Testing in preparation for 2014 recompletion to pick up attic oil from LLDSB #34
LLDSB #34	84,121	Preparation for sidetrack on schedule for second quarter 2014
	$944,856	

Additional development costs incurred during the year ended December 31, 2013, were reclassified to workover expense as those expenditures did not result in additional reserves; most notably $427,962 on the LLDSB #10 well and $212,240 spent on the LLDSB #2 well.

During the year ended December 31, 2012, the Company spent $1,546,723 on development of the Lake Hermitage field. Lake Hermitage field also includes three processing facilities and tank batteries. During the year ended December 31, 2012, the Company plugged and abandoned two wells, the Southdown 2D in Valentine field and the LLDSB #7 in Lake Hermitage field, retiring their costs comprising, solely, 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 the Company incurred $244,237 of environmental remediation expense in addition to the expense of plugging and abandoning the well and recognized a loss on the settlement of the asset retirement obligation of $116,394.

Valentine Field – Lafourche Parish, Louisiana

TNR owns an average 90% working interest, some of which is non-operated, in forty-one wells in the Valentine Field, of which twelve are currently producing, three are salt water disposal, and twenty-six are shut-in pending evaluation for future workover or recompletion.

During the year ended December 31, 2013, the Company spent $0 on development of the Valentine Field.

During the year ended December 31, 2012, the Company spent $859,316 on development of the Valentine Field, of which $743,292 was spent on the PPCO #1 Sidetrack. Due to technical problems with equipment, the sidetrack was abandoned in late December 2012. We believe the sidetrack was a geological success but a mechanical failure as a significant indication of natural gas was encountered during drilling. Costs for the sidetrack remain capitalized as the Company evaluates the feasibility of participating in a subsequent sidetracking of this well.

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Larose Field – Lafourche Parish, Louisiana

Various working interests, some of which are non-operated, are owned by TNR in eight wells in the Larose Field. There are two salt water disposal wells in the field and two wells are currently shut-in pending evaluation for future workover or recompletion. During the year ended December 31, 2013, the Company spent $0 on development of the Larose Field. During the year ended December 31, 2012, the Company spent $149,970 to upgrade its processing facility to better enable gas lift of the M.R.Fee 852 #1 well as well as to provide excess capacity for processing of third party production.

Bay Batiste Field, Plaquemines Parish, Louisiana

The Company owns an average 61% working interest in seven wells in the Bay Batiste Field, although only one well is currently producing. There is one salt water disposal well in the field. The other five wells are currently shut-in pending evaluation for future workover or recompletion. During the year ended December 31, 2013, the Company spent $0 on development of the Bay Batiste Field. During the year ended December 31, 2012, the Company spent $94,634 on the State Lease 9570 #3 well, to replace a large compressor for a smaller, more efficient compressor.

SE Manila Village Field – Plaquemines Parish, Louisiana

The two wells in the Manila Village field in which TNR owned a non-operated working interest have been plugged and abandoned by the operator.

Turkey Creek Field – Garfield and Major Counties, Oklahoma

During the year ended December 31, 2013, the Company spent $1,674,539 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 total costs of $2,591,770 charged to dry hole expense. The Company also impaired $57,945 in undeveloped leasehold costs associated with Section 29 and $20,000 in developed leasehold costs associated with the Traylor Unit #1.

During the year ended December 31, 2012, the Company acquired leasehold interests comprising 3,745 gross/3,105 net acres in Garfield and Major Counties, Oklahoma, spending $602,377; entered into a Farmout Agreement spending $140,000 and an additional $30,000 in leasehold costs; and spudded the Thomas Unit #6H well spending $936,488 and an additional $78,846 on the Thomas #5 water disposal well. Under the terms of the Farmout Agreement we may acquire approximately 1,760 net acres of leasehold should we meet certain obligations set forth therein, the most significant of which is a requirement to drill two wells over a thirty-six month period, one of which has already been drilled.

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 year ended December 31, 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 delivered the seismic data to Anadarko and is evaluating potential drilling sites and funding opportunities for the test well.

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.

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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. Shortly after we took over operatorship, the wells were shut in. The Company recognized a $212,160 impairment of the leasehold, leaving a fair value of $150,000.

As of October 1, 2013, the Company sold its Young County, Texas, properties for $131,250, recognized 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 of December 31, 2013, the purchaser has to develop the property and the Company has recorded a production payment receivable of $131,250.

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 $97,932, recognizing a loss of $7,981 on the sale.

Java Field Natural Gas Development Project – Wyoming County, New York

On August 31, 2009, the Company acquired the Java Field, a natural gas development project targeting the Marcellus Shale present in Wyoming County in western New York. The acquisition included 19 producing natural gas wells and their associated leases/units, two surface tracts of land totaling approximately 36 acres and two pipeline systems, including 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. Our average net revenue interest (NRI) in the leases is approximately 78%. Production from the wells is nominal but serves to hold the acreage for future development. In late 2009, we evaluated a number of the existing wells in order to determine the viability of the re-entry of existing wellbores for plug-back and recompletion of the wells in the Marcellus Shale. As a result of this evaluation, we selected the Reisdorf Unit #1 and the Ludwig #1 as our initial targets and these two wells were recompleted in the Marcellus Shale and fracked in May and June of 2010. The initial round of testing and analysis provided data that supports further development of the Marcellus in western New York.

As of December 31, 2010, the State of New York had placed a moratorium on high volume fracture stimulation in order to develop new permitting rules. The new permitting rules have not been completed and there can be no assurance when such permitting rules will be issued or what restrictions such permits might impose on producers. Accordingly, we are 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.

During the year ended December 31, 2013, there has been no change in the status of the moratorium, and the wells continue to produce on a marginally economic basis.

Asset Retirement Costs

During the year ended December 31, 2013, the Company revalued its asset retirement obligations and, as a result, recognized a decrease of $817,051 in its asset retirement costs associated with wells. See NOTE 6 – ASSET

RETIREMENT OBLIGATIONS.

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Support Facilities and Equipment

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

	Lives	December 31, 2013	2012
Tank batteries	7 - 12	$ 807,580	$ 789,043
Production equipment	7	1,034,599	1,001,943
Production facilities	7	108,702	55,544
Field offices	20	150,000	267,089
Crew boat	7	172,413	66,313
Construction in progress (not depreciated)	N/A	43,696	19,019
Asset retirement cost	7	786,828	256,363
Subtotal		3,103,818	2,455,314
Accumulated depreciation		(685,920)	(379,751)
Total support facilities and equipment, net		$ 2,417,898	$ 2,075,563

During the year ended December 31, 2013, the Company sold for $54,018 the land and building comprising the Lake Hermitage field office/camp which was seriously damaged by Hurricane Isaac in 2012. The net book value of the camp when sold was $119,467 ($109,467 – building, $10,000 – land), and a loss of $65,449 was incurred on the sale of the camp.

The Company also:

- revalued its asset retirement obligations as regard support facilities and equipment and increased the asset retirement cost by $530,464, the same amount as the increase in the asset retirement obligation (see NOTE 6 – ASSET RETIREMENT OBLIGATIONS);
- purchased for $106,100 new motors and a trailer for our crew boats;
- installed for $53,157 a gas lift system for Lake Hermitage;
- installed for $22,117 a sump pump and boom box for our MR Fee production facility in Larose field.

The Company recognized depreciation expense of $311,894 and $279,027 during the years ended December 31, 2013 and 2012, respectively.

Property and Equipment

	Lives	December 31, 2013	2012
Office equipment, computer equipment, purchased software, and leasehold improvements	3	$ 251,912	$ 203,972
Furniture and fixtures	10	55,569	53,346
Subtotal		307,481	257,318

Accumulated depreciation		(64,805)		(15,691)
Total property and equipment, net	$	242,676	$	241,627

During the year ended December 31, 2013, property and equipment increased by $50,163 from the year ended December 31, 2012. $40,000 of the increase was for the purchase of additional software licenses for the Company's ERP system; and $10,163 was for additions to computer equipment, office furniture, and leasehold improvements. The Company recognized depreciation expense of $49,114 and $12,838 during the years ended December 31, 2013 and 2012, respectively.

Support facilities and equipment, office equipment, computer equipment, purchased software, office furniture and fixtures, and leasehold improvements are depreciated using the straight line method over their estimated useful lives.

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NOTE 5 – DEBT

The Company’s notes payable consisted of the following at December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
Credit Facility	$ 8,222,693	$ 9,195,963
Notes issued pursuant to private placement of securities	655,000	—
Less: debt discount on private placement notes	(87,725)	—
Other term notes	79,582	90,417
Notes payable outstanding	8,869,550	9,286,380
Less: current maturities	(8,869,550)	(90,417)
Notes payable – noncurrent	$ —	$ 9,195,963

Credit Facility and Notes Payable

On July 22, 2011, the Company 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 December 31, 2013 and 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.

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.

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 provided for the reduction of the Borrowing base by $675,000 to $12,700,000 from $13,375,000; reset monthly repayments of principal to $50,000 per month until the next scheduled redetermination to occur on or about April 1, 2014, and required that general and administrative expense not exceed 27% of revenue for any two consecutive quarters. During the year ended December 31, 2013, the Company repaid $973,270 of principal on the credit facility.

At inception of the Credit Facility, deferred financing costs of $102,877 were incurred. During the years ended December 31, 2013 and 2012, $22,563 and $44,213, respectively, of amortized deferred financing costs had been recognized as interest expense. At December 31, 2013, $13,162 of deferred financing costs remained to be amortized.

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The Credit Facility contains covenants with which the Company must maintain compliance, among which are certain ratios. The Company determined that, at December 31, 2013, it was not in compliance with the interest coverage ratio, calculated at 1.88. On March 31, 2014, the Company received a default waiver from F&M Bank for the three months ended December 31, 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.

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 3 – Commodity Derivative Instruments.

For the years ended December 31, 2013 and 2012, the Company recognized interest expense of $520,146 and $315,628, 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(a)(2), Section 4(a)(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 December 31, 2013, the Company had received subscriptions for $655,000 ($300,000 of which was acquired in the Armada acquisition) 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 ($103,001 of which was acquired in the Armada acquisition) 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		205.74%
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 year ended December 31, 2013, the Company recognized interest expense of $47,656 on the face value of the notes, and amortization of the debt discount resulted in the recognition of $161,201 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. $87,725 of debt discount remains to be amortized at December 31, 2013.

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. During the year ended December 31, 2013, the Company had fully repaid this note, together with interest of $9,303.

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Gulfstar Convertible Note

On December 2, 2013, Gulfstar Resources, LLC, provided the Company $600,000 net of financing cost of $33,730 for net cash received of $566,270 in exchange for a promissory note with an interest rate of 10% per annum and a maturity date of January 1, 2014. This note was made in anticipation of the closing of the transaction by which Coral Reef Capital, LLC, acquired an equity interest in TNR Holdings, LLC ("TNRH") for a capital contribution into which the net proceeds of the note plus accrued interest would be included. On December 23, 2013, the transaction closed, the value of the note less the expenses plus accrued interest of $3,452, were included in the amount converted to Class A Units in TNRH.

Premium Financed Insurance Notes

During the year ended December 31, 2013, the Company repaid the December 31, 2012 outstanding balances of $44,638 and $43,711 of notes payable for prepaid insurance and entered into two new notes to finance insurance premiums of $129,465 (automobile and well control insurance) and $37,348 (boat insurance) at interest rates of 4.44% and 5.49%, respectively. Both notes are for terms of less than one year. At December 31, 2013, outstanding balances on these notes were $65,254 and $10,372, respectively.

Directors and Officers Liability Insurance Note

On March 29, 2013, the company entered into a premium financed note for directors and officers liability insurance in the principal amount of $38,938 at an interest rate of 4.31%. At December 31, 2013, the outstanding balance on this note was $3,957.

Debt Maturities

At December 31, 2013, the Company had no long-term debt, and all maturities are current.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated present value of asset retirement obligations for the years ended December 31, 2013 and 2012.

	For the Year Ended December 31,	
	2013	2012
Beginning asset retirement obligations	$ 3,507,798	$ 3,450,252
Obligations assumed from acquisition (1)	65,263	—
Revaluation of asset retirement obligations (2)	(468,519)	—
Accretion expense	172,927	196,903
Sale of Young and Archer County properties	(99,891)	—
Settlement of asset retirement obligations	(15,768)	(139,357)
Ending asset retirement obligations	$ 3,161,810	$ 3,507,798

(1) ARO of Archer and Young County, Texas, properties acquired in the Acquisition.
(2) ARO of Texas and Louisiana properties

During the year ended December 31, 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 of $15,768 was eliminated. In addition, the asset retirement obligation for wells in the Keller Prospect in Young County, Texas, was revalued and increased by $30,794 and then retired upon sale of the properties. The asset retirement obligation for the wells in Parish and Tribune Prospects in Archer County, Texas, was retired upon sale. Gains on sales and settlements of asset retirements obligations during the year ended December 31, 2013 were $3,428. At December 31, 2013, the Company provided $4,628,125 in letters of credit supporting its asset retirement obligations.

During the year ended December 31, 2012, the Company plugged and abandoned two wells, the Southdown 2D and the LLDSB #7, recognizing a loss on settlement of asset retirement obligations of $116,394. During the year ended December 31, 2011, the Company was required to provide letters of credit in the aggregate amount of $4,704,037 from its credit facility with F&M Bank supporting these obligations in addition to a $600,000 deposit placed with the State of Louisiana Department of Natural Resources, Office of Conservation. During the year ended December 31, 2012, the Company was refunded $30,579 of the deposit in place with the State of Louisiana Department of Natural Resources, Office of Conservation, and its letter of credit requirement by the State of Louisiana was reduced by $100,912 to $4,603,125. However, the Company was required by the Oklahoma Corporation Commission to provide a $25,000 letter of credit in conjunction with our 2012 drilling activity there. At December 31, 2012, the Company provided $4,628,125 in letters of credit.

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NOTE 7 – INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Components of our deferred income taxes as of December 31, 2013 and 2012 are as follows:

	December 31,	
Current Deferred Tax Assets/(Liabilities)	2013	2012
Imputed interest	$ 6,025	$ 6,315
Derivatives	—	32,010
Other	94,581	—
Net current deferred tax assets/(liabilities)	$ 100,606	$ 38,325

	December 31,	
Noncurrent Deferred Tax Assets/(Liabilities)	2013	2012
Difference in depreciation, depletion, and capitalization methods – oil and natural gas properties	$ 1,481,806	$ 693,710
Net operating losses	2,497,935	1,873,634
Share based compensation	988,341	511,306
Debt discount	149,622	—
Capitalized merger costs	385,284	—
Other	—	47,828
Total noncurrent deferred tax asset	$ 5,502,988	$ 3,126,478
Difference in depreciation, depletion, and intangible drilling costs - oil and natural gas properties	$ (3,685,274)	$ (668,254)
Other	(18,279)	(10,528)
Total noncurrent deferred tax liabilities	$ (3,703,553)	$ (678,782)
Net deferred tax asset/(liability)	$ 1,900,041	$ 2,486,021

The Company has US net operating loss carry forwards of approximately $7.35 million which begin to expire in 2028.

Utilization of the NOL is subject to a substantial annual limitation due to the ownership change limitations provided by the Internal Revenue Code of 1986, as amended. The Company does not expect any of its NOL carryforwards to expire unutilized as a result of existing ownership changes. If we incur an additional limitation, then the NOL carryforwards, as disclosed, could be reduced by the impact of any future limitation that would result in existing NOL carryforwards and tax credit carryforwards expiring unutilized.

In 2011, the Company achieved positive earnings, primarily due to the Company's successful acquisition of Tchefuncte Natural Resources LLC. Based on the weight of available objective evidence, management believes that it is more likely than not that its deferred tax asset will be realized. Accordingly, the Company eliminated its valuation allowance in 2011. The benefit from the reduction was recorded as a tax benefit in accordance with accounting standards for income taxes.

The Company recognizes 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 years ended December 31, 2013 and 2012. There were no interest and penalties related to unrecognized tax positions for the years ended December 31, 2013 and 2012. The tax years subject to examination by tax jurisdictions in the United States are 2010 through 2013.

As of December 31, 2013 and 2012, the Company recorded deferred tax assets, net of deferred tax liabilities, of $1,900,041 and $2,486,021, respectively.

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NOTE 8 – COMMITMENTS AND CONTINGENCIES

Contractual Obligations

The Company leases its corporate office in Dallas, Texas, a field office in Covington, Louisiana, and a residence to house crews at Lake Hermitage field at monthly rental amounts of $7,390, $6,851, and $1,800, respectively. The Dallas office subleases a portion of its square footage. In addition, the Company leases office space in California on a month-to-month basis at a monthly rental of $930. The Dallas office lease expires on July 31, 2015. The Covington office lease expires on March 31, 2014, but has been renewed effective April 1, 2014 (See NOTE 11 – SUBSEQUENT EVENTS). The Lake Hermitage residence lease expires March 14, 2014, but has been renewed effective April 1, 2014 (See NOTE 11 – SUBSEQUENT EVENTS). During the year ended December 31, 2013, the Company paid rent totaling $74,575 (net of reimbursement from sublessee), $66,210, $8,370, and $21,600 for its Dallas, Covington, and California offices and Lake Hermitage residence, respectively.

The Company also leases four trucks that are used in its field operations in Louisiana. The leases for these trucks qualify as operating leases. During the year ended December 31, 2013, the Company made total payments of $25,776 for the trucks.

The Company also leases a copier at monthly rental of $275. This lease expires on April 1, 2014. During the year ended December 31, 2013, the Company paid $3,300 in rental for the copier.

During 2013, the Company's rental expense was $213,936 for all operating leases.

During the year ended December 31, 2012, the Company leased its corporate office in Dallas, Texas, as well as a field office in Covington, Louisiana, at monthly rental amounts of $4,345 and $3,851, respectively. During the year ended December 31, 2012, the Company paid rent totaling $51,585 and $43,809 for its Dallas and Covington offices, respectively.

The Company also leased four trucks used in its field operations in Louisiana. The leases for these trucks qualify as operating leases. During the year ended December 31, 2012, the Company made total payments of $26,274 for the trucks.

During 2012, the Company's rental expense was $125,256 for all operating leases.

Information regarding all the Company's contractual lease obligations, at December 31, 2013, is set forth in the following table.

	Operating Leases
2014	$ 133,840
2015	56,730
2016 and thereafter	—
Total	$ 190,570

Contingencies

From time to time, the Company may become involved in various lawsuits and legal proceedings which arise in the ordinary course of business. However, litigation is subject to inherent uncertainties, and an adverse result in these or other matters that may arise from time to time that may harm the Company's business.

Other than routine litigation arising in the ordinary course of business that the Company does not expect, individually or in the aggregate, to have a material adverse effect on the Company, there are currently no pending legal proceedings.

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NOTE 9 – EQUITY

Common Stock

The following table shows the Company’s common stock activities for the year ended December 31, 2013:

	Common Shares Issued
Shares issued in Acquisition	21,094,633
Adjustment to Mesa Energy Holdings, Inc. common shares in Acquisition	(50,598,286)
Shares issued in conjunction with issuance of debt (See Note 5)	639,998
Shares issued as compensation (See Note 10) (1)	563,651
Total shares issued during the year ended December 31, 2013	(28,300,004)

(1) Restricted common stock with fair value of $380,515 which vested pursuant to grants awarded in 2013 to employees pursuant to our 2012 Long-term Incentive Plan (“2012 Incentive Plan”) (108,000 shares) and to consultants (455,651 shares). Fair value was determined by multiplying the number of shares granted by the closing price of the Company’s common stock on the date of grant.

The following table shows the Company’s common stock activities for the year ended December 31, 2012:

	Common Shares Issued
Shares issued as compensation (See Note 10) (1)	1,071,000
Shares issued to notes payable and accrued interest (See Note 5) (2)	3,728,153
Total shares issued during the year ended December 31, 2012	4,799,153

(1) Restricted common stock with fair value of $174,346 which vested pursuant to grants awarded in 2011 to employees pursuant to our 2012 Incentive Plan. Fair value was determined by multiplying the number of shares granted by the closing price of the Company’s common stock on the date of grant.

(2) Restricted common stock issued upon conversion of notes payable and accrued interest with fair value of $466,019 determined on date of conversion as set forth in Note 5.

Warrants

Pursuant to the Offering Modification (NOTE 5 – Debt), 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.

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Under a private placement commenced on March 20, 2013, Series D Warrants to purchase 873,333 common shares were issued at periodic closings through April 30, 2013, of which 400,000 were assumed under the Armada acquisition and 473,333 were issued after the consummation of the Armada acquisition. Each warrant became 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	$	0.53
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 year ended December 31, 2013 and 2012:

	Shares		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life		Aggregate Intrinsic Value
Outstanding at December 31, 2011	—	$	—	—	$	—
Granted	500,000		1.00	3.5 years		—
Adjusted at 0.4 to 1 for Armada acquisition (See NOTE 2)	(300,000)		N/A	N/A		N/A
Outstanding and exercisable at December 31, 2012	200,000	$	2.50	3.5 years	$	—
Assumed under Armada acquisition (See NOTE 2)	7,414,787		3.25	3.3 years		—
Modified	639,998		0.75	4.2 years		—
Granted	473,333		0.75	4.2 years		—
Exercised	—		—	—		—
Cancelled/Expired	(1,174,785)		1.25	—		—
Outstanding at December 31, 2013	7,553,333	$	1.96	4.2 years	$	—
Exercisable at December 31, 2013	7,553,333	$	1.96	4.2 years	$	—

During the year ended December 31, 2013, 1,174,785 of Series A Warrants with an exercise price of $1.25 expired.

During the year ended December 31, 2012, the Company terminated a consulting agreement in consideration for which the Company issued 500,000 cashless warrants (200,000 post Armada acquisition) which vested immediately and are exercisable at $2.50 per share for a period of five years. Each warrant entitles the holder to one share of the Company's common stock in the event of exercise.

The following table summarizes the value from and assumptions for the Black-Scholes option pricing model for warrants issued during the year ended December 31, 2012.

Grant date fair value	$	45,423

Weighted average risk-free interest rate		0.75%
Expected life (in years)		5
Weighted average volatility		136.27%
Expected dividends	$	—

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Noncontrolling Interest

The following table shows the Company’s common stock activities for the year ended December 31, 2013:

On December 16, 2013, the Company formed TNR Holdings, LLC, a Delaware limited liability company. On December 20, 2013, the Company entered into a Unit Purchase Agreement with Gulfstar Resources, LLC, (“Gulfstar”) pursuant to which Gulfstar agreed to contribute $6,250,000 of total capital ($600,000 of which was provided in the form of a note payable on December 2, 2013, see NOTE 5 – DEBT) in exchange for 6,250 Class A Units of TNRH membership interest at a price of $1,000 per Class A Unit, representing a 34.375% noncontrolling membership interest in TNRH (“Tranche A”). See summary of proceeds from Tranche A below:

Gross contribution commitment from Tranche A	$ 6,250,000
Less bridge note converted to Class A Units (See NOTE 5 – DEBT)	(600,000)
Less offering cost	(283,812)
Net proceeds from Tranche A	$ 5,366,188

Gulfstar is obligated to purchase an additional aggregate 11,873 Class A Units of TNRH from the Company at a price of $564.31 per Class A Unit ($6,700,053 in the aggregate), representing an additional 25.925% membership interest in TNRH by April 1, 2014 (“Tranche B”), and has an option to purchase from the Company up to an additional 9,718 Class A Units, at one or more additional closings, at a price of $468.20 per Class A Unit ($4,549,968 in the aggregate), representing an additional 9.7% membership interest in TNRH.

NOTE 10 – SHARE-BASED COMPENSATION

Stock Options

The Board of Directors of the Company previously adopted the 2012 Incentive Plan which provides for the issuance of incentive awards of up to 5,000,000 shares of common stock to officers, key employees, consultants and directors of the Company and its subsidiaries.

The following table summarizes the Company’s stock option activities for the years ended December 31, 2013 and 2012:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
Outstanding at December 31, 2011	2 228,000	$ 0.37	1.5 years	$ —
Granted	640,000	0.18		—
Exercised	—	—	—	—
Cancelled/Expired/Forfeited	(21,000)	0.17	—	—
Adjusted at 0.4 to 1 for Armada acquisition (See NOTE 2)	(1,708,200)	N/A	N/A	N/A
Outstanding at December 31, 2012	1,138,800	0.76	4.1 years	—
	1,064,000	1.06	0.9 years	—

Assumed under Armada acquisition (See NOTE 2)					
Granted (1)	2,052,000		0.39	4.1 years	—
Exercised	—		—	—	—
Cancelled/Expired/Forfeited (2)	(1,452,800)		0.91	—	—
Outstanding at December 31, 2013	2,802,000		0.41	3.9 years $	—
Exercisable at December 31, 2013	2,522,600	$	0.41	3.9 years $	—

(1) Comprises 240,000 shares of restricted stock grant converted to options on March 20, 2013, 1,720,000 options granted to directors, and 92,000 options granted to employees.
(2) Comprises 119,200 of expired options, 942,000 of forfeited unvested options previously granted to former officers and directors prior to the Armada Acquisition, 91,600 of forfeited vested and unvested options previously granted to employees, and 300,000 granted to directors which were cancelled and replace by new option grants,

During the year ended December 31, 2013, options to purchase 2,052,000 shares of the Company's common stock were granted to the Company's employees and directors. These options had a grant date fair value of $697,461.

During the year ended December 31, 2012, stock options to purchase 640,000 shares of the Company common stock were granted to the Company's employees. These stock options had a grant date fair value of $102,487.

The following tables summarize the values from and assumptions for the Black-Scholes option pricing model for stock options granted during the years ended December 31, 2013 and 2012:

		2013
Weighted average grant date fair value	$	0.34
Weighted average risk-free interest rate		0.49%
Expected life (in years)	4.8	
Weighted average volatility		158.8%
Expected dividends	$	-

		2012
Weighted average grant date fair value	$	0.19
Weighted average risk-free interest rate		0.54%
Expected life (in years)	4.8	
Weighted average volatility		146.8%
Expected dividends	$	-

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Share-based compensation expense of $682,272 and $129,638 related to stock options was recognized for 2013 and 2012, respectively. As of December 31, 2013 and 2012, the Company had $44,756 and $61,950 of unrecognized share-based compensation related to stock options remaining to be amortized. No stock options were exercised during 2013 and 2012.

Restricted Stock

The following table summarizes the Company's restricted stock activity for the years ended December 31, 2013 and 2012:

	Shares
Unvested Restricted Shares at December 31, 2011	1,941,000
Granted	200,000
Vested	(1,071,000)
Forfeited	(200,000)
Unvested Restricted Shares at December 31, 2012	870,000
Adjusted at Acquisition (1) (See NOTE 2)	(522,000)
Granted	455,651
Vested	(563,651)
Cancelled (2)	(240,000)
Unvested Restricted Shares at December 31, 2013 (2)	—

(1) 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 year ended December 31, 2013.

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

During the year ended December 31, 2013, the Company issued 108,000 shares of restricted stock to its employees and 455,651 shares of restricted stock to consultants, all of which vested in 2013. The fair value of restricted stock issued to consultants was $344,875, of which $325,000 was allocated to the purchase price of the Acquisition and not recognized in expense.

During the year ended December 31, 2012, 200,000 shares of the Company restricted stock were granted to the Company's employees. These shares had a grant date fair value of $36,000.

The Company had, at December 31, 2013 and 2012, respectively, $0 and $104,400, of unrecognized compensation expense related to outstanding restricted stock. Share-based compensation related to restricted stock grants of $55,550 and $174,346 was recognized in the years ended December 31, 2013 and 2012, respectively.

NOTE 11 – SUBSEQUENT EVENTS

On the January 22, 2014, the Company unwound the crude oil basis swaps for the February 2014 through December 2014 settlement periods. Volumes unwound were 55,000 barrels with an original basis price of $4.85 per barrel unwound at a basis price of $4.95 per barrel. The Company incurred a loss of $5,500 in unwinding these positions.

On March 11, 2014, the Company filed with the Oklahoma Secretary of State Articles of Amendment to the articles of organization of its subsidiary, MMC Resources, LLC, by which the name of this subsidiary was changed to Armada

Midcontinent, LLC.

On March 14, 2014, the Company entered into a purchase and sale agreement with Piqua Petro, Inc., pursuant to which we will purchase from Piqua Petro its interests in six oil and gas leases covering approximately 1,040 acres in Woodson County, Kansas. The Company will pay the seller $6,500,000 in cash for the leases (subject to an adjustment in our favor for production revenue received by the seller for production from and after March 1, 2014, and an adjustment in favor of the seller for its operating costs on and subsequent to March 1, 2014). The Company has paid a $100,000 non-refundable earnest money deposit and will pay the balance at closing, which both we and the seller are obligated to use best efforts to effect by April 3, 2014. The capital to be used for closing is expected to come from the closing of Tranche B of the Gulfstar Transaction (See NOTE 9). We will acquire 100% of the leasehold working interest in the lands covered by the leases, subject to royalties, overriding royalties and other expense-free burdens on production that do not exceed 12.5% of 8/8ths, such that the net revenue interest in the leases conveyed to us will not be less than 87.5%. The agreement contains certain indemnification and other customary provisions.

Effective April 1, 2014, Mesa Gulf Coast, LLC, extended its leases on its Covington office and its Lake Hermitage residence. The Covington office lease was renewed through March 31, 2016 at a monthly rental of $7,832, with an option to extend the lease at a monthly rental of $8,485 commencing April 1, 2016, for a term of 23 months. The Lake Hermitage residence lease was renewed through February 1, 2016, at a monthly rental of $1,800. Future rental obligations under these leases is as follows:

		Operating Leases
2014	$	86,688
2015		115,584
2016 and thereafter		25,296
Total	$	227,568

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NOTE 12 – SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION ACTIVITIES (UNAUDITED)

The Company’s oil and gas properties and proved reserves are located in the United States.

Capital Costs

Capitalized costs and accumulated depletion relating to the Company’s oil and gas producing activities as of December 31, 2013 and 2012 are summarized below:

	2013	2012
Undeveloped properties not being amortized	$ 10,653,825	$ 759,133
Proved properties being amortized	12,660,155	12,893,468
Accumulated depreciation, depletion and impairment	(4,967,452)	(3,810,942)
Net capitalized costs	$ 18,346,528	$ 9,841,659

Acquisition, Exploration, and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities for the years ended December 31, 2013 and 2012 are summarized below:

	2013	2012
Proved acreage	$ 151,421	$ —
Undeveloped acreage	9,952,637	759,133
Development costs	1,484,542	3,691,975
Exploration expense	284,275	115,276
	$ 11,872,875	$ 4,566,384

Results of Operations

	2013 Quarter Ended			
	March 31	June 30	September 30	December 31
Net revenues from production:				
Sales of oil and gas production	$ 3,414,420	$ 3,086,862	$ 3,266,014	$ 2,518,526
Production Expenses:				
Oil and gas operating expense	1,853,195	2,414,415	1,621,231	1,582,126
Exploration expenses	2,585,062	117,150	391,677	72,261
Depreciation, depletion, and amortization	690,955	203,027	241,833	350,146
Results of operations before income tax expense:	$ (1,714,792)	$ 352,270	$ 1,011,273	$ 513,993
Income tax benefit (expense)	583,029	(119,772)	(343,833)	(174,758)
Results of operations	$ (1,131,763)	$ 232,498	$ 667,440	$ 339,235

Results of operations for producing activities comprise all activities associated with our exploration for and production of oil and gas. Net revenues from production include only the revenues from the production and sale of natural gas, oil, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are those incurred to operate and maintain wells and related equipment and facilities used in oil and gas operations. Exploration expenses include dry hole expenses, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion, and amortization allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

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Reserve Information and Related Standardized Measure of Discounted Future Net Cash Flows

Supplemental Oil and Gas Reserve and Standardized Measure Information

The supplemental unaudited presentation of proved reserve quantities and related standardized measure of discounted future net cash flows provides estimates only and does not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, significant changes to these estimates can be expected as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are those estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The standardized measure of discounted future net cash flows is computed by applying the average first day of the month price of oil and gas during the 12 month period before the end of the year (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

The reserve estimates set forth below were prepared by third party engineering firms using reserve definitions and pricing requirements prescribed by the SEC. Ralph E. Davis Associates, Inc. ("Davis"). Davis is an independent consultant, does not own any interest in the Company's properties, and is not engaged contingent upon the value of the Company's properties. Davis prepared reserves estimates for our Louisiana properties by performance methods, volumetric methods, analogy, or a combination of methods. Performance methods generally included decline-curve analysis and material balance analysis where representative data was available. Volumetric estimates generally included a combination of geological and engineering interpretations, while analogy methods included reserve estimates from historical performance of similar wells and reservoirs in the field or nearby fields. The data utilized were furnished to Davis by the Company or obtained from public data sources. Davis is a professional engineering firm specializing in the technical and financial evaluation of oil and gas assets.

Estimated quantities of oil and natural gas reserves

The following table sets forth certain data pertaining to changes in reserve quantities of the proved, proved developed, and proved undeveloped reserves for the year ended December 31, 2013 and 2012.

	December 31,			
	2013		2012	
	Crude Oil (Bbls)	Natural Gas (Mcf)	Crude Oil (Bbls)	Natural Gas (Mcf)
TOTAL PROVED RESERVES				
Beginning of year	2,140,200	5,562,884	2,200,300	7,933,297
Purchases of minerals in place	—	—	—	—

Extensions and discoveries	1,103,008	6,141,036	546,800	361,100
Revisions of previous estimates	(22,062)	1,433,563	(494,735)	(1,989,422)
Production	(100,126)	(456,113)	(112,165)	(742,091)
End of period	3,121,020	12,681,370	2,140,200	5,562,884
PROVED DEVELOPED RESERVES				
Proved developed producing	644,840	2,857,980	378,000	1,511,000
Proved developed nonproducing	175,230	2,322,200	110,000	700,000
End of period	820,070	5,180,180	488,000	2,211,000
Total proved undeveloped	2,300,950	7,501,190	1,652,200	3,351,884

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The standardized measure of discounted future net cash flows relating to the proved oil and gas reserves is computed using average first-day-of the-month prices for oil and gas during the 12-month periods ended December 31, 2013 and 2012 (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated related future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated), and assuming continuation of existing economic conditions.

Future income tax expenses give effect to permanent differences and tax credits but do not reflect the impact of continuing operations including property acquisitions and exploration. The estimated future cash flows are then discounted using a rate of ten percent a year to reflect the estimated timing of the future cash flows.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relating to the proved crude oil and natural gas reserves as of December 31, 2013 and 2012 is presented below.

Net cash flows at December 31,	2013	2012
Future cash inflows	$ 380,215,130	$ 251,927,900
Future production costs	(110,045,029)	(58,224,400)
Future development costs	(50,633,990)	(35,690,300)
Future income tax expense	(71,519,884)	(49,824,667)
Future net cash flows	148,016,227	108,188,533
10% annual discount for estimated timing of cash flow	(57,972,758)	(42,390,895)
Standard measure of discounted future net cash flows related to proved reserves	$ 90,043,469	$ 65,797,638

The principal sources of changes in the standardized measure of the future net cash flows for the two years ended December 31, 2013 and 2012 are:

	2013	2012
Balance, beginning of period	$ 65,797,638	$ 73,756,837
Sales and transfers of oil and gas produced during the period	(4,839,930)	(7,468,883)
Net change in sales price, net of production costs	(11,857,860)	(9,105,410)
Net changes due to extensions and discoveries	69,652,153	20,157,700
Changes in estimated future development costs	(14,086,502)	15,765,181
Previously estimated development costs incurred during the period	(1,148,091)	(2,345,055)
Net change due to revisions in quantity estimates	7,103,228	(32,772,963)
Other	(15,902,254)	(2,921,362)
Accretion of discount	9,926,350	10,537,613
Net change in income tax	(14,601,263)	193,980

Balance, end of period	$	90,043,469	$	65,797,638

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Effect of Gulfstar Transaction on the Company's Interest in the Reserves

Our reserves are associated with properties owned by TNR in Louisiana and by Mesa Midcontinent, LLC ("MMC") in Oklahoma. Pursuant to the Amended and Restated Limited Liability Company Agreement of TNR Holdings LLC ("TNRH"), dated as of December 20, 2013, the Company owns a 65.625% interest in the earnings of TNRH effective January 1, 2014. As a result, effective January 1, 2014, the Company will have the following interest in the net proved reserves as set forth above as follows:

	January 1, 2014	
	Crude Oil (Bbls)	Natural Gas (Mcf)
PROVED DEVELOPED RESERVES		
Proved developed producing	423,176	1,875,549
Proved developed nonproducing	114,995	1,523,944
End of period	538,171	3,399,493
Total proved undeveloped (1)	1,573,788	5,560,553

In addition, once Tranche B funding under the Unit Purchase Agreement by and Among TNR Holdings LLC, Mesa Energy, Inc., Armada Oil, Inc., and Gulfstar Resources, LLC dated as of December 20, 2013, occurs on or after April 1, 2014, the Company's interest in the earnings of TNRH will be reduced from 65.625% to 39.7%. As a result, the Company will then have the following interest in the net proved reserves as set forth above as follows:

	Upon Funding of Tranche B	
	Crude Oil (Bbls)	Natural Gas (Mcf)
PROVED DEVELOPED RESERVES		
Proved developed producing	256,001	1,134,618
Proved developed nonproducing	69,566	921,913
End of period	325,567	2,056,531
Total proved undeveloped (1)	1,025,376	4,096,960

(1) Reserves owned by MMC are classified as proved undeveloped as follows:

Oil (Bbls)	185,570
Gas (Mcf)	1,855,700