MILLER ENERGY RESOURCES, INC.
Form 10-K
July 15, 2013

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

FORM 10-K

(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended: April 30, 2013
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________________ to ____________________________

MILLER ENERGY RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Tennessee	001-34732	62-1028629
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

9721 Cogdill Road, Suite 302, Knoxville, TN 37932
(Address of Principal Executive Office) (Zip Code)
(865) 223-6575
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	New York Stock Exchange
10.75% Series C Cumulative Redeemable Preferred Stock, par value $0.0001 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None
(Title of Class)

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

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

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.
þ Yes ¨ 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).
þ Yes ¨ 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 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.
¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.

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

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

The aggregate market value of the outstanding common stock, other than shares held by persons who may be deemed affiliates of the registrant, computed by reference to the closing sales price for the registrant's common stock on October 31, 2012 (the last business day of the registrant's most recently completed second quarter), as reported on the New York Stock Exchange-Composite Index, was approximately $159,097,613. As of July 5, 2013, there were 43,446,694 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant's proxy statement relating to registrant's 2013 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

MILLER ENERGY RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED APRIL 30, 2013

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

We have made forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning the Company's operations, economic performance and financial condition in this report, our Annual Report on Form 10-K for the year ended April 30, 2013 and may make other forward-looking statements from time to time in other public filings, press releases and discussions with our management. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should" or similar expressions or variations on such expressions. For these statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that our expectations will prove to be correct. We undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- the potential for us to experience additional operating losses;
- material weaknesses in our internal control over financial reporting and our need to enhance our management, systems, accounting, controls and reporting performance;
- high debt costs under our existing senior credit facility;
- potential limitations imposed by debt covenants under our senior credit facility on our growth and our ability to meet our business objectives;
- our ability to meet the financial and production covenants contained in the Apollo Credit Facility;
- whether we are able to complete or commence our drilling projects within our expected time frame;
- litigation risks;
- our ability to perform under the terms of our oil and gas leases, and exploration licenses with the Alaska DNR, including meeting the funding or work commitments of those agreements;
- uncertainties related to deficiencies identified by the SEC in our Form 10-K for 2011;
- our ability to successfully acquire, integrate and exploit new productive assets in the future;
- whether we can establish production on certain leases in a timely manner before expiration;
- our ability to complete the work commitments required as terms of our Susitna Basin Exploration Licenses;
- our ability to recover proved undeveloped reserves and convert probable and possible reserves to proved reserves;
- our experience with horizontal drilling;
- risks associated with the hedging of commodity prices;
- our dependence on third party transportation facilities;
- concentration risk in the market for the oil we produce in Alaska;
- the impact of natural disasters on our Cook Inlet Basin operations;
- the effect of global market conditions on our ability to obtain reasonable financing and on the prices of our common and Series C Preferred Stock;
- the imprecise nature of our reserve estimates;
- risks related to drilling dry holes or wells without commercial quantities of hydrocarbons;
- fluctuating oil and gas prices and the impact on our results from operations;
- the need to discover or acquire new reserves in the future to avoid declines in production;
- differences between the present value of cash flows from proved reserves and the market value of those reserves;
- the existence within the industry of risks that may be uninsurable;
- strong industry competition;
- constraints on production and costs of compliance that may arise from current and future environmental, FERC and other statutes, rules and regulations at the state and federal level;

- new regulation on derivative instruments used by us to manage our risk against fluctuating commodity prices;
- the impact that future legislation could have on access to tax incentives currently enjoyed by us;
- that no dividends may be paid on our common stock for some time;

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- cashless exercise provisions of outstanding warrants;
- market overhang related to restricted securities and outstanding options, and warrants;
- the impact of non-cash gains and losses from derivative accounting on future financial results;
- risks to non-affiliate shareholders arising from the substantial ownership positions of affiliates;
- the junior ranking of our Series C Preferred Stock to our Series B Preferred Stock and all of our indebtedness;
- our ability to pay dividends on the Series C Preferred Stock;
- whether our Series C Preferred Stock is rated;
- the ability of our Series C Preferred Stockholders to exercise conversion rights upon a Change of Control;
- fluctuations in the market price of our Series C Preferred Stock;
- whether we issue additional shares of Series C Preferred Stock or additional series of preferred stock that rank on parity with the Series C Preferred Stock;
- the very limited voting rights held by our Series C Preferred Stockholders;
- the newness of the Series C Preferred Stock and its limited trading market;
- risks related to our continued listing of the Series C Preferred Stock on the NYSE; and
- the effect of the change of control conversion feature of our Series C Preferred Stock on a potential change in control.

Most of these factors are difficult to predict accurately and are generally beyond our control. You should consider the areas of risk described in connection with any forward-looking statements that may be made herein. Readers are cautioned not to place undue reliance on these forward-looking statements, and readers should carefully review this annual report in its entirety, including the risks described in Item 1A. Risk Factors. Except for our ongoing obligations to disclose material information under the Federal securities laws, we undertake no obligation to release publicly any revisions to any forward-looking statements, to report events or to report the occurrence of unanticipated events. These forward-looking statements speak only as of the date of this annual report, and you should not rely on these statements without also considering the risks and uncertainties associated with these statements and our business.

OTHER PERTINENT INFORMATION

We maintain our web site at www.millerenergyresources.com. On our website, you will find detailed information regarding our company, our locations and our leadership team, as well as information for shareholders and investors on our media and investor pages. Information on this web site is not a part of this annual report.

Unless specifically set forth to the contrary, when used in this annual report on Form 10-K, the terms “Miller Energy Resources,” "Miller," the "Company," "we," "us," "ours," and similar terms refers to our Tennessee corporation Miller Energy Resources, Inc., formerly known as Miller Petroleum, Inc., and our subsidiaries, Miller Rig & Equipment, LLC, Miller Drilling, TN LLC, Miller Energy Services, LLC, East Tennessee Consultants, Inc. ("ETC"), East Tennessee Consultants II, LLC ("ETCII"), Miller Energy GP, LLC, and Cook Inlet Energy, LLC ("CIE").

Our fiscal year end is April 30. The year ended April 30, 2013 is referred to as “fiscal 2013” or "2013," the year ended April 30, 2012 is referred to as “fiscal 2012” or "2012," the year ended April 30, 2011 is referred to as “fiscal 2011” or "2011" and the year ending April 30, 2014 is referred to as “fiscal 2014” or "2014."

GLOSSARY OF OIL AND NATURAL GAS TERMS

We are engaged in the business of exploring and producing oil and natural gas as well as exploiting our mid-stream assets that could entail electrical power sales, processing third party fluids and natural gas and waste disposal. Many of the terms used to describe our business are unique to the oil and gas industry. The definitions set forth below apply to the indicated terms as used in this annual report on Form 10-K.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas corrected to standard temperature and pressure.
Bopd. Barrels of oil per day.
Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil.

Boe/d. Boe per day.
Mcf. One thousand cubic feet of natural gas corrected to standard temperature and pressure.
Mcfd. One thousand cubic feet of natural gas per day.
MMBbls. Million barrels of oil.
MMcf. Million cubic feet of natural gas corrected to standard temperature and pressure.
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.
Development well. A well drilled within the proved areas of oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Downstream. Refers to oil and gas infrastructure or operations relating to the refining, manufacturing, or sales of sales-quality crude oil or natural gas. This term is used in contrast to upstream (exploration and production) or midstream (transportation and ancillary services).
Dry hole or dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.
Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
Midstream. Refers to oil and gas infrastructure or operations relating to the transportation of sales-quality crude oil and gas production facilities to market. Used to contrast to upstream (exploration & production) or downstream (refining, manufacturing and sales).
Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.
Oil and gas lease or lease. An agreement between a mineral owner, the lessor, and a lessee which conveys the right to the lessee to explore for and produce oil and gas from the leased lands. Oil and gas leases usually have a primary term during which the lessee must establish production of oil and or gas. If production is established within the primary term, the term of the lease generally continues in effect so long as production occurs on the lease. Leases generally provide for a royalty to be paid to the lessor from the gross proceeds from the sale of production.
Proved developed non-producing reserves ("PDNP"). Proved crude oil and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.
Proved developed producing reserves ("PDP"). Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.
Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves. The quantities of oil and gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible. We provide information on two types of proved reserves - developed and undeveloped.
Proved undeveloped reserves ("PUD"). Reasonably certain reserves in drilling units immediately adjacent to the drilling unit containing a producing well as well as areas beyond one offsetting drilling unit from a producing well.
Reservoir. A porous or permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty interest. A right to oil, gas, or other minerals that is not burdened by the costs to develop or operate the related property.

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Upstream. Refers to oil and gas infrastructure or operations relating to the exploration and production of crude oil and gas and its processing into sales-quality crude or gas. Used to contrast to midstream (transportation and ancillary services) or downstream (refining, manufacturing and sales).

Working interest. An interest in an oil and gas property that is burdened with the costs of development and operation of the property.

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PART I

ITEM 1 AND 2. BUSINESS AND PROPERTIES.

Overview
We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration, development and operation of oil and gas wells in the Appalachian region of east Tennessee and in southcentral Alaska. Occasionally, during times of excess capacity, we offer these services, on a contract basis, to third-party customers primarily engaged in our core competency - natural gas exploration and production.
During fiscal 2013, we continued to develop our oil and gas operations acquired from Pacific Energy Resources ("Pacific Energy") in December 2009 through a bankruptcy proceeding, including onshore and offshore production and processing facilities, the offshore Osprey platform, and approximately 700,000 lease or exploration license acres of land, along with hundreds of miles of 2-D and 3-D geologic seismic data, miscellaneous roads, pads, pipelines and facilities. Our mission is to grow a profitable exploration and production company for the long-term benefit of our shareholders by focusing on the development of our reserves, continued expansion of our oil and natural gas properties and increase in our production and related cash flow. We intend to accomplish these objectives through the execution of the following core strategies:

- Develop Acquired Acreage. We will focus on organically growing production through drilling for our own benefit on existing leases and acreage in the exploration licenses with a view towards retaining the majority of the working interest in the new wells. This strategy will allow us to maintain operational control, which we believe will translate to long-term benefits;
- Increase Production. We plan on increasing oil and gas production through the maintenance, repair and optimization of wells located in the Cook Inlet region and development of wells in the Appalachian region of east Tennessee. Our operational team will employ a combination of the latest available technologies along with tried and true technologies to restore as well as explore and develop our properties;
- Expand Our Revenue Stream. We intend on fully exploiting our mid-stream facilities, such as our injection wells and the Kustatan Production Facility, our ability to engage in the commercial disposal of waste generated by oil and gas operations, and our capacity to process third party fluids and natural gas and to offer excess electrical power to net users in the Cook Inlet region; and
- Pursue Strategic Acquisitions. We have significantly increased our oil and gas properties through strategic low-cost / high-value acquisitions. Under the same strategy, our management team will continue to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We plan to leverage our management team's expertise to pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

For a more in-depth discussion of our fiscal 2013 results and our capital resources and liquidity, please see Part II, Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Recent Developments
Drilling Activities
On June 20, 2013, the RU-2 Sidetrack ("RU-2A") well was completed and was successfully brought online. After clearing the well of drilling fluids from the sidetrack, a subsequent well test showed an initial daily production rate (IP) of 1,281 barrels of oil per day (bopd) and a water cut of 19%. RU-2A is one of five planned sidetracks to be completed on the Osprey Platform.
The original RU-2 well, drilled by a previous operator, produced approximately 500,000 barrels before it suffered casing damage caused by a poor completion design. After assessing the deficiencies that resulted in the sub-optimal production and eventful catastrophic well failure, we re-engineered the drilling and completion to achieve optimal oil recovery on re-entry. RU-2A was sidetracked from the original RU-2 well starting at a depth of approximately 8,500 feet and drilled to a measured depth of 15,265 feet. The completed well has a new bottom hole located 46 feet higher on structure than the original RU-2 well.

We are currently drilling Olson Creek with Rig 34. Upon completion, we plan to move Rig 34 to deepen the Otter #1 prospect, which discovered the presence of reservoir quality sands and strong gas shows earlier this year.

Series C Preferred Stock

Pursuant to our At Market Issuance Sales Agreement, dated October 12, 2012 ("ATM Agreement") with MLV & Co. LLC ("MLV"), between May 1, 2013 and July 5, 2013, we offered and sold an additional 43,180 shares of our Series C Preferred Stock, at prices ranging from $22.01 and $22.35 per share. The Company received $953 in gross proceeds as a result of these sales, from which MLV was paid a commission of $33. These securities are registered for sale to the public pursuant to a prospectus

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supplement, dated September 19, 2012, and a prospectus supplement dated October 12, 2012, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

Pursuant to an Underwriting Agreement, dated May 7, 2013, with MLV, for itself and as representative of the underwriters listed on Schedule I to that agreement, on May 10, 2013, we offered and sold an additional 500,000 shares of our Series C Preferred Stock, at a price of $22.25 per share. We received gross proceeds of $11,125 in connection with the offering from which MLV was paid a commission of $765. These securities are registered for sale to the public pursuant to a prospectus, dated September 19, 2012, a prospectus supplement dated May 7, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

Pursuant to an Underwriting Agreement, dated June 27, 2013, with MLV, for itself and as representative of the underwriters listed on Schedule I to that agreement, on July 2, 2013, we offered and sold an additional 335,000 shares of our Series C Preferred Stock, at a price of $21.50 per share. We received gross proceeds of $7,200 in connection with the offering from which MLV was paid a commission of $504. These securities are registered for sale to the public pursuant to a prospectus, dated September 19, 2012, a prospectus supplement dated June 28, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

Apollo Credit Facility Waiver and Amendment

On July 11, 2013, we entered into an Amendment (the “July 2013 Amendment”) with Apollo Investment Corporation ("Apollo") under the Apollo Credit Facility. The fee for the Amendment was $100. The Amendment makes the following changes to the Apollo Credit Facility among others: (i) changes the initial testing date for those financial and production covenants referred to as the "maintenance covenants" to October 31, 2013; (ii) allows transfers of working interests by the Company to the Tennessee Oil and Gas Association; (iii) reduces the restrictions on the transfer of the Company's stock by senior management; and (iv) allows for a later delivery date for certain routine deliverables otherwise called for under the related loan agreement with Apollo.

Geographic Area Overview

We currently focus our efforts on activities in the Cook Inlet and Susitna Basins of Alaska as well as the Appalachian region of east Tennessee.

The following table sets forth certain key information for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2013 Production	Percentage of Total 2013 Production	2013 Oil and Gas Revenues	4/30/2013 Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves
	(In Boe)			(In MBoe)	
Cook Inlet [1]	276,908	87%	$27,932	8,445	98%
Appalachian region	40,698	13%	1,983	166	2%
Total	317,606	100%	$29,915	8,611	100%

1 Cook Inlet production excludes 57,123 boe of natural gas produced and used as fuel gas.

Alaska Region

Overview

The Cook Inlet Basin contains large oil and gas deposits including multiple offshore fields. In 2013 there were 16 platforms in the Cook Inlet, the oldest of which is the XTO A platform first installed by Royal Dutch Shell plc in 1964, and the newest of which is the Osprey platform installed by Forest Oil Corporation in 2000 and acquired by us in December 2009. Southcentral Alaska has a well-developed oil and gas pipeline infrastructure to bring Cook Inlet oil and gas to market. This system is isolated from the main North American gas pipeline system. Much of the value-added hydrocarbon processing occurs on the east side of Cook Inlet in an industrial cluster located in Nikiski, which is the northern part of the city of Kenai. The Tesoro refinery, ConocoPhillips LNG plant, BP GTL plant, Agrium, Inc. fertilizer plant, and numerous docks, tanks and pipelines are all located in Nikiski. The Susitna Basin is a large area to the north of Anchorage in southcentral Alaska. It is perhaps best known for its coal seams in the sedimentary basin that lies underneath the basin and could become a new source of much-needed natural gas.

Cook Inlet and Susitna Basins

The Cook Inlet is a vast estuary stretching 180 miles from the Gulf of Alaska to Anchorage in southcentral Alaska. The Inlet separates the Kenai Peninsula in the east from the Alaska Peninsula in the west. The Cook Inlet Basin underlying this region contains large oil and gas deposits including several offshore fields. There are also numerous oil and gas pipelines located in and

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under the Cook Inlet. The Cook Inlet Basin has produced approximately 1.3 billion barrels of oil and 7.8 trillion cubic feet ("tcf") of natural gas.

The Susitna Basin underlies the sprawling Susitna River valley to the north of Anchorage. The Susitna Basin lies directly north of the Cook Inlet Basin, separated by the Castle Mountain Fault, and has similar geology. While the Cook Inlet Basin is a historic region of oil and gas production, there is not currently commercial production of oil or gas from the Susitna Basin.

In its 2011 Assessment of Undiscovered Oil and Gas Resources of the Cook Inlet Region, the United States Geologic Survey ("USGS") estimated mean undiscovered technically recoverable reserves of 599 million bbls of oil and 19 tcf of natural gas. All of the undiscovered oil and 13.7 tcf of the undiscovered gas are conventional resources, and 5.3 tcf of natural gas was estimated to be technically recoverable as coal bed methane. This report considered the full oil and gas potential of the Cook Inlet Basin, but only the coal-bed methane potential of the Susitna Basin. These numbers do not include oil and gas remaining to be produced in currently producing fields.

As of April 30, 2013 and 2012, we owned approximately 100,099 and 105,713 gross acres of leasehold interests, the exploration license rights to an additional 580,147 acres and interests in 10 crude oil and five natural gas wells. The reduction in leased acreage from April 30, 2012 is a result of the expiration of three leases.

At the time we acquired the Alaskan operations, all ten oil wells, four of five gas wells and four injection wells were shut-in. As of April 30, 2013, four oil wells and five gas wells are producing. In addition, we own a 30% working interest in two gas wells operated by Aurora Gas, which have been operated continuously.

Oil wells drilled in this area range from 9,000 feet to 10,000 feet in vertical depth while gas wells have a vertical depth of 3,000 feet to 9,000 feet. Wells that are deviated (continue on from the vertical depth either diagonally or horizontally) will have a longer measured depth of approximately 5,000 feet to 9,000 feet or more giving measured depth of up to 19,000 feet or more. Well spacing is quite variable, as there are large parts of Cook Inlet which are completely undeveloped and others that are more mature. Our fields have approximately 60 acre spacing. The Cook Inlet Basin contains a thick section of terrestrial tertiary rocks which includes shale, sandstone, and coal. The primary targets in the area are crude oil reserves, but prolific gas fields are increasingly attractive due to the rising price of gas in the Alaska market and liquefied natural gas ("LNG"). Cook Inlet natural gas is strategically situated to provide LNG to Asian markets where the LNG price is high and rising.

Osprey Platform and Redoubt Shoals Field

The Osprey platform is located in the Redoubt Unit approximately 1.8 miles southeast of West Foreland in central Cook Inlet at a water depth of approximately 45 feet. The Osprey platform, which produces from the Redoubt Shoals Field is connected to our Kustatan Production Facility. It relies on our Kustatan Production Facility and our West McArthur River Unit Production Facility to provide all of its electricity and gas, and on the Kustatan Production Facility to process all of Osprey's produced fluids. The platform has 21 available slots, eight of which are currently used, and an attached 48 man camp. After a period of inactivity, we started work to re-commission Osprey in February 2011 and restored production in May 2011.

The Osprey platform was placed on site in June 2000 and initially used to conduct exploration drilling operations between January 2001 and July 2002. Eight wells were drilled, which in their present configuration consist of one water flood well, one Class I injection well, and six oil wells. The oil wells were equipped with electrical submersible pumps (“ESPs”) which were necessary to bring the oil to the surface. In 2005, the third-party drilling rig was removed from the platform after a contract dispute. The removal of the rig delayed the ability to maintain and repair the platform's wells or to expand production, and the Osprey platform was shut-in in the spring of 2009.

In order to restore production from the Redoubt Unit, it was necessary to mobilize a drilling rig to the Osprey platform to repair the shut-in wells. Two of the wells required replacement of the ESPs, and the other four wells required re-drilling in sections. Due to significant drilling rig rental cost and delays associated with mobilization and availability of a drilling rig sufficient in size and power to repair the wells, we determined it was most effective to permanently locate a drilling rig on the Osprey platform. In March 2011, we transitioned the Osprey platform out of lighthouse mode and successfully repaired the first of the two wells needing ESP replacement, of which one later failed in September 2011 as a result of successive pump failure. In June 2011, we contracted with Voorhees

Equipment and Consulting, Inc. for the custom construction and purchase of Rig 35 for $17,900.

We successfully mobilized all components of the custom rig to the Osprey platform in late December 2011. Assembly of the rig began as parts were delivered to the platform. In January 2012, the region experienced prolonged, near-record cold weather, which caused us to temporarily delay rig assembly efforts due to safety concerns. The cold weather also led to significant generation of ice volume in the Cook Inlet and made shipping and the operation of work-boats very limited. As warmer temperatures moderated the region and rig contractor and supplies were in order, we resumed work on the assembly of Rig 35, which was brought online in August 2012. Rig 35 has since replaced pumps in oil wells RU-1 and RU-7, sidetracked oil well RU-2A and completed the reworking of the RU-3 and the RU-4 gas wells. We were unable to optimize the performance of RU-1 due to obstructions which were stuck in the lower part of the well bore. We are currently performing a side track on this well bore.

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Kustatan Production Facility
The Kustatan Production Facility was constructed in 2002 by Forest Oil Corporation to process an estimated 25,000 bopd. Processing capabilities are expandable to 50,000 bopd. The facility provides power and processes hydrocarbons produced from our offshore Osprey platform.
West McArthur River Field and Production Facility
The West McArthur River Facility processes oil and gas from the West McArthur River Field and has the ability to process gas from the West Foreland Field. Currently, there are three producing wells in the field. The facility was built in 1990s to process approximately 5,000 bopd.
West Foreland Field and Production Facility
The West Foreland Field is produced through the West Foreland Facility but can be processed through the West McArthur River Facility. Currently, there are three wells in the field, one of which is off-line. The West Foreland Facility is tied into the gas pipeline network including sales gas pipelines.
Three Mile Creek Field
The three Mile Creek Field is operated by Aurora Gas. There are two gas wells in which we own a 30% working interest in this field.
Susitna Basin
Included in the Alaskan operations we acquired is a 100% interest in Susitna Basin Exploration License No. 2, granted by the State of Alaska in October 2005 covering approximately 471,474 acres in the Susitna basin area north of Anchorage. Under the terms of the Exploration License, the licensee was granted a seven-year exclusive license to explore for oil and gas on the specified lands, and upon fulfillment of the work commitment, the license for all or any part of the land could be converted into oil and gas leases. The original work commitment of approximately $3,000 was fulfilled. In an effort to control the timing of the development of this acreage, in April 2010 we requested a three-year extension of the exploration license for a work commitment of $750. The State granted the extension in October 2010. We will have the right to convert all or any portion of the licensed acreage into oil and gas leases upon completion of the new work commitment. We currently have a performance bond of $415 toward fulfilling its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area. The Susitna Basin Exploration License No. 2 is set to expire on October 31, 2013 and we expect to have fulfilled our work commitment obligation by such date. We will evaluate whether to convert all or any part of the license to leases at such time.
On April 1, 2011, we were awarded Susitna Basin Exploration License No. 4, which consists of 62,909 acres. It granted us an exclusive ten-year license to explore for oil and gas on the specified lands. Upon fulfillment of a $2,250 work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We currently have a performance bond of $281 toward fulfilling its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area.
On April 1, 2012, we were awarded Susitna Basin Exploration License No. 5, which consists of 45,764 acres. It granted us an exclusive five-year license to explore for oil and gas on the specified lands. Upon fulfillment of a $250 work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We currently have a performance bond of $63 toward fulfilling its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area.
Assignment Oversight Agreement
On November 5, 2009, CIE entered into an Assignment Oversight Agreement ("AOA") with the Alaska Department of Natural Resources ("Alaska DNR") which set out certain terms under which the Alaska DNR would approve the transfer of oil and gas leases owned by the State of Alaska from Pacific Energy to CIE. This agreement remains in place following our acquisition of CIE in December 2009. Generally, the agreement requires CIE to provide the Alaska DNR with additional information and oversight authority to ensure that CIE is acting diligently to develop the oil and gas from Redoubt and West McArthur River units ("WMRU"). Under the terms of the AOA, until the Alaska DNR determines that CIE has completed certain development and operational commitments relating to the WMRU and Redoubt Units, CIE must do the following, in addition to the normal requirements under the terms of the leases:

- file a monthly summary of expenditures by oil and gas field, tied to objectives in CIE's business plan and plan of development previously presented to the Alaska DNR,
- file a quarterly summary of expenditures by oil and gas field, tied to objectives in CIE's business plan and plan of development previously presented to the Alaska DNR,
- meet monthly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,

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- notify the Alaska DNR 10 days prior to commitment when CIE is preparing to spend funds on a purchase, project or item relating to the WMRU or Redoubt Leases of more than $5,000,
- annually submit a new plan of development for the Alaska DNR's approval.

The AOA required CIE to demonstrate funding commitments of $5,150 to support the redevelopment of the WMRU and an estimated $31,000 to support the development of the Redoubt Unit. The Company believes it has adequately fulfilled these commitments.

On March 11, 2011, the Company entered into a Performance Bond Agreement under its AOA with the state of Alaska. Under the Performance Bond Agreement, the Company is required to post a total bond of $18,000 for the dismantling and abandonment of the properties. As agreed with the state of Alaska, the Performance Bond Agreement fulfills our commitment under the AOA to fund the full dismantlement costs with respect to our onshore and offshore assets. The Performance Bond Agreement also stipulated that $6,628 held by the state in an escrow account will be credited towards the $18,000. As a result, the Company recorded a $6,910 gain on acquisition (inclusive of accrued interest) during the year ended April 30, 2011.

The AOA also prohibits CIE from using proceeds from operation at WMRU or Redoubt for non-core oil and gas activities, or activities unrelated to WMRU or Redoubt, without the prior written approval of the Alaska DNR until the parties mutually agree that the full dismantlement obligation under the assigned leases is funded.

Failure to submit the information required by the AOA or expenditure of proceeds from WMRU or Redoubt for items or activities unrelated to core oil and gas activities at WMRU or Redoubt would constitute a default under the AOA. If the default could not be cured within 30 days, the leases would be subject to termination by the Alaska DNR.

Membership in Cook Inlet Spill Prevention and Response, Inc. ("CISPRI")

CIE is a member of the CISPRI. CISPRI is a non-profit corporation formed in 1990 to provide oil spill prevention and response capabilities in Cook Inlet. CISPRI has been designated as a Class "E" Oil Spill Removal Organization by the U.S. Coast Guard, which is the highest level of designation based on spill containment and removal equipment requirements for offshore/ocean response. CISPRI's response zone includes the entire Cook Inlet region. At each annual meeting of CISPRI members adopt a budget for the coming year which includes funds for day to day operational activities of CISPRI, investments in capital equipment and materials to be used in connection with the cleanup activities and research and development and training. The budget is funded though payment of dues by the members and the amount of dues is calculated in accordance with a participation formula. We pay an annual fee of $50 together with additional fees based upon the amount of oil we transport.

If a spill of crude oil/synthetic crude oil or refined petroleum products is identified as originating from facilities owned or operations conducted by one or more of the members, CISPRI will act to control and clean up the spill without any further action by the members. Any member that utilizes or receives the benefit of these activities must reimburse CISPRI for all expenses of control and clean up, including costs of equipment, materials and personnel. Each member is required to execute a response action contract providing terms and conditions under which response and cleanup activities will be undertaken. CIE is a party to such an agreement which, in part, requires CIE to maintain worker's compensation insurance, employers' liability insurance, comprehensive general and automotive liability insurance covering injury or death or persons and property damage of at least $10,000. CIE is in compliance with these insurance requirements. All members accept responsibility for spills which result from their operations or facilities and have indemnified CISPRI and all other members for all liabilities arising for a spill. This indemnification is not limited by the amount of insurance coverage.

CIE may resign its membership in CISPRI upon 30 days written notice. At the effective date of the resignation, CIE is obligated to pay all unpaid dues and assessments levied prior to the notice of resignation. CIE's membership may be terminated by the Board of Directors of CISPRI upon 60 days notice if it is determined CIE is no longer eligible for membership. CIE would not be entitled to a refund of any monies paid to CISPRI.

Appalachian Region

We are the largest owner/operator of oil and natural gas wells in Tennessee. As of April 30, 2013, we owned approximately 50,260 gross acres of leasehold interests with 193 producing oil wells and 191 producing gas wells in which we own an interest. This is an increase of 1,000 gross acres, 10 oil wells and 10 gas wells from April 30, 2012.

Wells drilled within our acreage range from approximately 1,500 to 4,200 feet in depth with major targets in descending order being: the Mississippian age Monteagle Limestone and Fort Payne Limestone, and the Devonian age Chattanooga Shale, with the Fort Payne Limestone being the primary oil target.

During fiscal 2013, Miller focused its emphasis on continuing the purchase of working interests in wells in order to increase the number of wells in which we own an interest, thus increasing production. In addition we focused on reworks of older producing wells, and drilling horizontal wells in the Mississippian age Fort Payne Limestone. With the strategic purchases of

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working interests, reworks, and drilling new wells; net oil production in Tennessee increased from 46 bbls per day at April 30, 2012 to 55 bbls per day at April 30, 2013. Gas production has stayed flat due to restrictions on gas sales in the area.

In January 2013, we drilled and completed the first successful horizontal oil well in the Fort Payne Limestone in Tennessee. This well has confirmed the viability of this type of drilling technique in the Mississippian age limestone formations in Tennessee. We are presently producing from this well, and since the well is a first of its kind we are experimenting with various production techniques. Miller drilled a second horizontal well in the Fort Payne Limestone and we are still in the completion phase of this well.

This drilling and production method, along with gas pressure maintenance, will enable us to maximize the oil potential in Tennessee. We have acreage in and around previously producing fields and plan to utilize our expertise to enhance present production and extract additional oil from areas previously overlooked. Currently, within the acreage controlled by us, there are numerous potential well locations that can be drilled and produced. In addition, we will continue to pursue a pressure maintenance program and natural gas storage within the Mississippian age Fort Payne Limestone.

Miller has millions of cubic feet of gas shut-in and behind pipe in Tennessee. With the price of natural gas moving upward, we plan on moving forward to secure markets for this gas. In addition to the gas shut-in and behind pipe, the Devonian age Chattanooga Shale underlies acreage controlled by us and is a candidate for horizontal gas wells in the future.

Principal Markets and Customers

The existing markets for natural gas production in southcentral Alaska are the Tesoro Nikiski Refinery, utility companies, petrochemical manufacturing, the production of LNG for export to Asian markets, and the production of synthetic crude oil (“syncrude”). Presently, our sole market for crude oil produced from our Alaskan operations is the Tesoro Nikiski Refinery. Crude oil is shipped by pipeline and tanker vessel to the Tesoro Nikiski Refinery, operated by Tesoro Alaska Petroleum Company ("Tesoro").

Under the terms of the Alaska crude oil sales contract, Tesoro has agreed to purchase all crude oil produced by us, subject to a minimum of 200 bbls/day and a maximum of 24,000 bbls/day. Should the quantity of oil produced by us fall below the minimum or rise above the maximum, the contract would be open for renegotiation.

The price for each delivery of oil shall be equal to the simple arithmetic average of the published daily NYMEX WTI for the applicable front month NYMEX Contract published each business day in the calendar month of delivery, subject to certain adjustments: (i) If the ANS Index Midpoint Price is at least $2.285/bbl greater than the WTI Index Price, then the price shall be equal to the ANS Index Midpoint Price less $4.00/bbl; (ii) If the ANS Index Midpoint Price is equal to or less than the sum of the WTI Index Price plus $2.285/bbl, then the price shall be equal to the WTI Index Price less $1.715/bbl; (iii) less a deduction for the CISPRI; (iv) less a deduction for transportation through the Kenai Pipeline; (v) less a deduction for transportation and shipping, and; (vi) less a deduction adjusting for Redoubt Shoal quality. Non-Redoubt Shoal oil will have an additional quality adjustment.

We are also responsible for paying taxes on the sale, production or handling of the oil prior to delivery. The contract may be opened for renegotiation if the quality of the oil changes, certain volume reductions or increases, changes to the CISPRI charges, or closure of the company's Alaska Refinery. In fiscal 2013, 2012 and 2011, purchases by Tesoro accounted for 100%, 100%, and 99%, respectively, of our total Alaska oil and gas production revenues.

Currently, approximately 1.5 MMcfd to 3.0 MMcfd of natural gas produced by our Alaskan operations is used to generate heat and power at our production facilities. In the near future, gas production in excess of our internal needs will be sold to third parties, as all of our gas wells are connected to the Southcentral Alaska Railbelt pipeline network through the Cook Inlet Gas Gathering System and/or the Beluga Pipeline, both of which are operated by Hilcorp Alaska, LLC and its affiliates.

The principal markets for our crude oil and natural gas produced in the Appalachian region are refining companies, utility companies and private industry end users. Crude oil is stored in tanks at the well site until the purchaser retrieves it by tank truck. Direct purchases of our crude oil are made by Barrett Oil Purchasing Company, Sunoco, and

Kentucky Oil and Refining Company. Our natural gas has multiple markets throughout the eastern United States through gas transmission lines. Access to these markets is presently provided by three companies in northeastern Tennessee: Cumberland Valley Resources, NAMI Resources Company, and Tengasco. Local markets in Tennessee are served by Citizens Gas Utility District and the Powell Clinch Utility District. Natural gas is delivered to the purchaser via gathering lines into the main gas transmission line. Surplus gas is placed in storage facilities or transported to East Tennessee Natural Gas which serves Tennessee and Virginia. In fiscal 2013, 2012 and 2011, sales to Barrett Oil Purchasing and Sunoco, collectively, represented approximately 81%, 35%, and 2%, respectively, of our total Tennessee oil and gas revenues.

Drilling Statistics

Historically, our drilling activities have generally concentrated on the recompletion of wells in the Cook Inlet region and the exploitation and extension of existing producing fields in the Appalachian region. In fiscal 2012, we transitioned our efforts to the construction of a custom rig for the Osprey platform, Rig 35, with the anticipation that it will restore all previously producing wells on the platform. During fiscal 2013 and early fiscal 2014, we have used Rig 35 to restore or commence production from oil wells RU-1, RU-7 and RU-2A and gas wells RU-3 and RU-4. Rig 35 is currently being used to sidetrack the RU-1 oil well.

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We also made significant improvements and modifications to one of our rigs, Rig 34, to enable onshore drilling in winter conditions while complying with Alaska regulations. Upon certification from the Alaska Oil and Gas Conservation Commission ("AOGCC") in March 2012, we mobilized Rig 34 to the Kustatan gas field to workover the KF-1 well, a previously producing gas well, and to the Otter Prospect in April 2012 to begin drilling the Otter 1 well. Rig 34 is currently working on the Olson Creek #1 well, which was spudded on June 25, 2013.

In 2013, we incurred dry hole costs on one well in Tennessee. In Tennessee, we drilled two new development wells; one well that is producing and one well that is classified non-producing as of the year end. In 2012, we explored two new zones in our KF-1 well in Alaska that were unproductive. The cost of exploring the two new zones was expensed in 2012.

The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years:

	Drilling Activities					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Producing						
Cook Inlet	—	—	—	—	—	—
Appalachian region	1	1	—	—	—	—
Total producing	1	1	—	—	—	—
Non-Producing						
Cook Inlet	—	—	—	—	—	—
Appalachian region	1	1	—	—	—	—
Total non-producing	1	1	—	—	—	—
Injection						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total injection	—	—	—	—	—	—
Dry						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	2	2	—	—
Total dry	—	—	2	2	—	—
Total development	2	2	2	2	—	—
Exploratory:						
Productive						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	3	3
Total productive	—	—	—	—	3	3
Dry						
Cook Inlet	—	—	1	1	—	—
Appalachian region	1	1	—	—	—	—
Total dry	1	1	1	1	—	—
Pending determination	—	—	—	—	—	—
Total exploratory	1	1	1	1	3	3
Total drilling activity	3	3	3	3	3	3

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Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of April 30, 2013 is set forth below:

	Producing Wells					
	Gross [(a)]			Net [(b)]		
	Oil	Gas	Total	Oil	Gas	Total
Cook Inlet	5	9	14	4	6	10
Appalachian region	193	191	384	132	128	260
Total	198	200	398	136	134	270

(a) The number of gross wells is the total number of wells in which an interest is owned.

(b) The number of net wells is the sum of fractional interests we own in gross wells expressed as whole numbers and fractions thereof.

Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, net oil and gas production volumes, average sales prices, and average production cost per boe after deducting royalties and interests of others, with respect to oil and gas production attributable to our interest. Average production cost presented within the table are costs incurred to operate, to maintain the wells and equipment, and to pay the production costs, which does not include transportation, ad valorem and severance taxes per unit of production.

	For the Year Ended April 30,		
	2013	2012	2011
Net production - boe[1]	374,729	405,799	327,712
Average oil price - per bbl	$101.53	$93.10	$75.75
Average natural gas price - per mcf	$3.52	$3.47	$4.77
Average lease operating expenses - per boe[2]	$59.48	$27.86	$24.93

1 Net production for fiscal 2013, 2012 and 2011 includes 57,123, 33,956 and 34,987 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

2 Fiscal 2013 average lease operating expenses per boe includes $7,462 in workover expenses.

Gross and Net Undeveloped and Developed Acreage

Our staff of professional geologists utilizes results from logs, seismic data and other tools to evaluate existing wells and to predict the location of economically attractive new natural gas and oil reserves. To further this process, we have collected and continue to collect logs, core data, production information and other raw data available from state and private agencies and other companies and individuals actively drilling in the regions being evaluated. From this information, the geologists develop models of the subsurface structures and formations that are used to predict areas for prospective economic development.

On the basis of these models, we obtain available natural gas and oil leaseholds, farm-outs and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and an annual rental payment, converting to a royalty upon initial production. In addition, overriding royalty payments may be granted to third parties in conjunction with the acquisition of drilling rights initially leased by others.

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial work is performed with respect to discovered defects which we deem to be significant. Title examinations have been performed with respect to substantially all of our producing properties.

Certain of the properties we own are subject to royalty, overriding royalty and other outstanding interests customary to the industry. The properties may also be subject to additional burdens, liens or encumbrances customary to the industry, including items such as operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with the use of the properties.

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The following table presents our gross and net acreage position in each region where we have operations as of April 30, 2013:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Cook Inlet	39,153	32,106	641,093	623,244	680,246	655,350
Appalachian region	11,500	7,760	38,760	32,117	50,260	39,877
Total acreage	50,653	39,866	679,853	655,361	730,506	695,227

The following table presents the net undeveloped acres that we control under fee leases and exploration licenses and the period the leases and exploration license are scheduled to expire, absent pre-expiration drilling or production which extends the term of the lease(s) or the fulfillment of the exploration license terms which permits us to convert all or any portion of the exploration license into oil and gas leases. The expiration dates of the leases are subject to one year automatic renewals so long as we are producing oil and/or gas on the lease. In Alaska, three leases (Gross & Net 12,553 acres) expired May 31, 2012, the State of Alaska issued ADL 391877 (Gross & Net 160 acres), and acreage was added to one of the Olson Creek Mental Health Trust leases (Gross & Net 1,660 acres).

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Lease/Exploration License	Net Undeveloped Acres Fiscal Year of Expiration	Total Acres
Cook Inlet		
MHT 9300062 - Olson Creek	2014	5,483
MHT 9300063 - Olson Creek	2014	5,566
ADL 391613 - Olson Creek	2018	107
ADL 391614 - Olson Creek	2018	35
ADL 391615 - Olson Creek	2018	570
ADL 391623 - N Alexander	2018	5,513
ADL 391877 - N Alexander	2020	160
ADL 390749 - Otter	2014	2,522
ADL 390579 - Otter	2012, Held by Drilling	5,760
ADL 391621 - Otter	2018	2,528
ADL 391624 - Otter	2018	2,514
ADL 390078 - Susitna Basin #2 Exploration License	2013	471,474
ADL 391628 - Susitna Basin #4 Exploration License	2021	62,909
ADL 391794 - Susitna Basin #5 Exploration License	2017	45,764
ADL 390735 - Stingray	2013	2,047
ADL 391608 - Tazlina	2018	5,760
ADL 17602 - Sabre/Sword	1967, Held by Unit	896
ADL 18758 - Sabre	1967, Held by Unit	280
ADL 17594	1967, Held by Unit	80
ADL 17597	1967, Held by Unit	1,280
ADL 18730	1967, Held by Unit	480
ADL 18777	1967, Held by Unit	553
ADL 390368 - Kustatan	2010, Held by Well	963
Total		623,244
Appalachian region		
Lindsay	Held by production	1,439
Edwards-Fowler	Held by production	55
Gunsight	Held by production	1,468
Phillips et al from Gunsight acreage	Held by production	1,031
KTO acreage	Held by production	24,586
Baker-Senior lease farm out	Held by production	1,590
Other Undeveloped, net	2014	1,948
Total		32,117
Total acreage		655,361

Oil and Natural Gas Reserves

"Proved reserves" are the quantities of oil and gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible. We provide information on two types of proved reserves - developed and undeveloped. "Proved developed reserves" are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and "proved undeveloped reserves" are reasonably certain reserves in drilling units immediately adjacent to the drilling unit containing a producing well, as well as areas beyond one offsetting drilling unit from a producing well.

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“Unproved reserves” are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, or regulatory uncertainties preclude such reserves being classified as proved. They are sub-classified as probable and possible. Probable reserves are attributed to known accumulations and usually claim a 50% confidence level of recovery. Possible reserves are attributed to known accumulations that have a less likely chance of being recovered than probable reserves. This term is often used for reserves which are claimed to have at least a 10% certainty of being produced. Reasons for classifying reserves as possible include varying interpretations of geology, reserves not producible at commercial rates, uncertainty due to reserve infill, and projected reserves based on future recovery methods.

The following table shows proved oil and gas reserves as of April 30, 2013, based on average commodity prices in effect on the first day of each month in fiscal 2013, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. This table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products. All of our proved reserves are located in the United States.

	Net Reserves at April 30, 2013			
Reserves category:	Oil (MBbls)	Natural Gas (MMcf)	MBoe	Reserve %
PROVED				
Developed				
Cook Inlet	1,576	244	1,617	19%
Appalachian region	121	269	166	2
Undeveloped				
Cook Inlet	6,257	3,427	6,828	79
Appalachian region	—	—	—	—
Total Proved	7,954	3,940	8,611	100%

Our estimates of proved reserves, proved developed reserves and proved undeveloped ("PUD") reserves as of April 30, 2013, 2012 and 2011, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Supplemental Oil and Gas Disclosures (Unaudited) set forth in Part IV, Item 15 of this Form 10-K. Estimated future net cash flows were calculated using a discount rate of 10% per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

In fiscal 2013, we did not develop any PUDs. We anticipate developing four of our offshore PUDs in Alaska's Redoubt Unit during fiscal 2014, including Redoubt 2A, 5B, 9 and 4A. Depending on the availability of an onshore drilling rig, we also plan on developing two PUDs in Alaska's West MacArthur River Field in fiscal 2014 including WMRU 8 and 9.

Preparation of Oil and Gas Reserve Information

Our reserve estimates for oil and natural gas as of April 30, 2013 for our Cook Inlet and Appalachian region assets were prepared by Ralph E. Davis Associates, Inc., an independent engineering firm. Our reserve reports, which are filed as exhibits to this annual report, were prepared using engineering and geological methods widely accepted in the industry. All reserve definitions comply with the applicable definitions of the rules of the SEC. The accuracy of the reserve estimates is dependent upon the quality of available data and upon independent geological and engineering interpretation of that data. For the proved developed producing reserves, the estimates were made when considered to be definitive, using performance methods that utilize extrapolations of various historical data including, but not limited to, oil, gas and water production and pressure history. For the other proved producing, proved behind pipe reserves, proved undeveloped reserves, and probable and possible reserves estimates were made using volumetric methods.

Our reserve estimates for oil and natural gas as of April 30, 2012 and 2011 for our Cook Inlet assets were prepared by Ralph E. Davis Associates, Inc. Our reserve estimates for oil and natural gas at April 30, 2012 for our Appalachian region assets were prepared by Ralph E. Davis Associates, Inc., and by Lee Keeling and Associates, Inc., as of April 30, 2011.

Internal Controls over Reserves Estimate

Our reserve estimates are in compliance with the SEC definitions and guidance and were prepared by an independent engineering firm. Our Chief Executive Officer of CIE and Acting Chief Financial Officer are primarily responsible for the engagement and oversight of our independent engineering firms. We provide the engineering firms with estimate preparation material such as property interests, production, current operation costs, current production prices and other information. This

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information is reviewed by the Chief Executive Officer of CIE and our Acting Chief Financial Officer prior to submission to our third party engineering firm. Letters which identify the professional qualifications of each of the independent engineering firms who prepared the reserve reports are included in those reserve reports which are filed as exhibits to this annual report. There was no conversion of unproved reserves to proved reserves during the fiscal year ended April 30, 2013.

Other Ancillary Services
We also generate ancillary revenues from facility rentals, services and drilling activities. While the facilities, equipment and personnel on hand are for the benefit of servicing and drilling our own properties, from time to time we optimize unused capacity by renting space and performing services and drilling on behalf of third parties. In fiscal 2013, 51% of our other revenues related to a road and pad building project in Alaska. In fiscal 2012 and 2011, 29% and 35%, respectively, of our other revenue related to a plugging project for the U.S. Department of Interior in Tennessee.

Competitive Conditions
Our oil and gas exploration activities in Alaska and Tennessee are undertaken in a highly competitive and speculative business environment. In seeking any other suitable oil and gas properties for acquisition, we compete with a number of other companies doing business in Alaska, Tennessee and elsewhere, including large oil and gas companies and other independent operators, many with greater financial resources than we have.
At the local level, as we seek to expand our lease holdings, we compete with several companies who are also seeking to acquire leases in the areas of the acreage which we have under lease. In Alaska, we have nine significant competitors consisting of Apache Corporation, Aurora Gas, Buccaneer Alaska, Hilcorp, ConocoPhillips, Furie, XTO, Linc Energy, and NordAq. However, we believe we can effectively compete because we already have existing oil and gas production, facilities, infrastructure, and pipelines that connect us to the oil and gas markets. We believe that our existing Alaska oil and gas reserves and current leases with large acreage positions enhance our competitive position within the area and will enable us to compete effectively for additional lease acreage with our competitors. In the Appalachian region, we have five significant competitors consisting of Atlas Energy Resources, LLC, Consol Energy, Inc., Can Argo Energy Corporation, Champ Oil, and Tengasco, Inc. These companies are in competition with us for oil and gas leases in known producing areas in which we currently operate, as well as other potential areas of interest. We have more than 40 years of experience in the Appalachian region and are the largest operator of oil and gas wells in Tennessee.

Government Regulation
While the prices of oil and natural gas are set by the market, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for oil production and natural gas depends on several factors beyond our control. These factors include regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of oil and natural gas, to prevent waste of oil and natural gas, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies.
Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of natural gas and oil, the development, production and marketing of natural gas and oil and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. The permits and approvals include those for the

drilling of wells. Additionally, other regulated matters include the following:

- bond requirements in order to drill or operate wells;
- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of well properties;
- the plugging and abandoning of wells; and
- the disposal of fluids.

The Regulatory Commission of Alaska regulates the intrastate pipeline tariffs and encompasses all pipelines CIE ships through including the Cook Inlet Pipeline Company ("CIPL"), CIGGS, and Beluga lines. The Regulatory Commission of Alaska must also review and approve most major long-term gas sales contracts to public utilities, and through this mechanism plays the

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dominant role in determining gas pricing, since Alaska has no spot market for gas. Southcentral Alaska gas is typically sold under long or short term contracts as opposed to a spot market. For the purposes of reasonably valuing gas reserves, therefore, future gas production is assumed to be sold at contract terms comparable to similarly situated producers.

CIE has posted $800 in Alaska and federal bonds. The Alaska DNR requires $600 in bonding to operate oil and gas leases on state lands, and the AOGCC requires a $200 bond to drill wells in the state. These bonds are fully funded and are held by the First National Bank of Alaska in certificates of deposit for benefit of the various beneficiaries.

CIE has a total of $909 in designated accounts to satisfy future abandonment obligations. A $324 letter of credit is established for two Class 1 non-hazardous injection wells for benefit of the United States Environmental Protection Agency (“EPA”). This letter of credit is backed by an account which must maintain a minimum value of $324. Under the terms of the bankruptcy sale of the Pacific Energy assets, CIE was obligated to establish accounts to cover abandonment obligations to Cook Inlet Region, Inc. (“CIRI”), Salamatof Native Association (“Salamatof”), and the State of Alaska; $585 was required to cover future abandonment expenses related to the three West Foreland gas wells for benefit of CIRI, all of which has been funded. An additional $750 is for future abandonment expenses associated with surface facilities and pipelines for benefit of CIRI and Salamatof, none of which has yet been funded.

In March 2011, CIE entered into a Performance Bond Agreement that set the bond for the Osprey platform at an inflation-adjusted $18,000. The agreement sets a payment schedule totaling $12,000 in annual payments between July 2013 and July 2019. An existing interest bearing account containing approximately $7,011 as of April 30, 2013 is to be credited against the inflation-adjusted $18,000 liability. Annual payments will be made after 2019 as necessary to the degree that inflation has caused the liability to increase over the amount contained in the funded accounts.

Under the Oil Pollution Act of 1990, CIE is required to fund a citizens advisory group, the Cook Inlet Regional Citizen's Advisory Council, under which its commitment is approximately $60 per year.

Tennessee law requires that we obtain state permits for the drilling of oil and gas wells and to post a bond with the Tennessee Oil and Gas Board to ensure that each well is reclaimed and properly plugged when it is abandoned. The reclamation bonds cost $1,500 per well. The cost for the plugging bonds range from $2,000 to $3,000 per well depending on depth or $20,000 for ten wells. Currently, we have several old $10 blanket plugging bonds which covers up to 10 wells. For most of the reclamation bonds, we have deposited a $2 certificate of deposit with the Tennessee Oil and Gas Board.

Sales of natural gas in Tennessee are affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the Federal Energy Regulatory Commission ("FERC"), which sets the rates and charges for transportation and sale of natural gas, adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. The stated purpose of FERC's changes is to promote competition among the various sectors of the natural gas industry. In 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas by pipeline. Every five years, FERC will examine the relationship between the change in the applicable index and the actual cost changes experienced by the industry. We are not able to predict with certainty what effect, if any, these regulations will have on us.

The state and regulatory burden on the oil and natural gas industry generally increases our cost of doing business and affects our profitability. While we believe we are presently in compliance with all applicable federal, state and local laws, rules and regulations, continued compliance (or failure to comply) and future legislation may have an adverse impact on our present and contemplated business operations. Because such federal and state regulations are amended or reinterpreted frequently, we are unable to predict with certainty the future cost or impact of complying with these laws.

We are subject to various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (“CERCLA”), the Resource Conservation and Recovery Act (“RCRA”), the Clean Air Act, and the Federal Water Pollution Control Act of 1972 (the "Clean Water Act"), which affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

CERCLA, also known as "Superfund," imposes liability for response costs and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a "hazardous substance"

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into the environment. These persons include the "owner" or "operator" of a disposal site and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary 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.

We currently lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, we could be required to do the following:

- remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators, and/or
- clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

The 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 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 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.

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. The Clean Water Act requires us to construct a fresh water containment barrier between the surface of each drilling site and the underlying water table. This involves constructing pit(s) and inserting heavy gauge plastic in the pit(s) in order to keep any drilling fluids and/or oil from escaping the drill site and contaminating the ground water and/or any navigable waters. 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 oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain 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 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.

Our operations are also subject to laws and regulations requiring removal and cleanup of environmental damages under certain circumstances. Laws and regulations protecting the environment have generally become more stringent in recent years, and may in certain circumstances impose "strict liability," rendering a corporation liable for environmental damages without regard to negligence or fault on the part of such corporation. Such laws and regulations may expose us to liability for the conduct of operations or conditions caused by others, or for acts which may have been in compliance with all applicable laws at the time such acts were performed. The modification of existing laws or regulations or the adoption of new laws or regulations relating to environmental matters could have a material adverse effect on our operations.

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In addition, our existing and proposed operations could result in liability for fires, blowouts, oil spills, discharge of hazardous materials into surface and subsurface aquifers and other environmental damage, any one of which could result in personal injury, loss of life, property damage or destruction or suspension of operations. We have an Emergency Action and Environmental Response Policy Program in place. This program details the appropriate response to any emergency that management believes to be possible in our area of operations. We believe we are presently in compliance with all applicable federal and state environmental laws, rules and regulations; however, continued compliance (or failure to comply) and future legislation may have an adverse impact on our present and contemplated business operations.

Employees

On April 30, 2013, we had 79 employees.

Offices

Our principal executive offices are located at 9721 Cogdill Road, Suite 302, Knoxville, Tennessee. At April 30, 2013, we maintained regional exploration and/or production offices in Huntsville and Sunbright, Tennessee and Anchorage, Alaska. We lease all of our primary administrative offices in Knoxville, Tennessee and Anchorage, Alaska. The current lease on our principal executive office runs through 2016. For more information regarding our obligations under office leases, please see Management's Discussion and Analysis of Financial Condition and Results of Operations under the caption "Contractual Obligations" set forth in Part II, Item 7 of this Form 10-K.

Our History

We were formed in Delaware in November 1985. In January 1997, we acquired Miller Petroleum, Inc., a privately-held company controlled by Mr. Deloy Miller, our Chairman, in a reverse merger in which Miller Petroleum, Inc. was the accounting survivor. In conjunction with this transaction, we changed our name to Miller Petroleum, Inc. and re-domesticated to the State of Tennessee.

From 1997 to 2008, we focused our operations on our existing acreage in the State of Tennessee. During this time, we participated in a joint venture with Wind City Oil & Gas, LLC (“Wind City”), which resulted in the drilling of ten successful natural gas wells on our Koppers, Lindsay, and Harriman acreage. However, a dispute arose between Wind City and us as to the winding up of the joint venture, and it was ultimately resolved after we were able to sell some of the acreage to Atlas Energy Resources, LLC (“Atlas”), in 2008. The Atlas transaction was subject to unwinding pursuant to a pending litigation between our company and CNX Gas Company, LLC as disclosed in Item 3. Legal Proceedings.

In August 2008, we hired Scott M. Boruff as our Chief Executive Officer, and began to look for opportunities to expand our acreage and operations by acquiring other businesses and forming strategic partnerships with other exploration and production companies. During Mr. Boruff's tenure as CEO, we have acquired the assets of one company, and acquired sole ownership of three companies.

The first acquisition under Mr. Boruff's leadership was the KTO transaction in which we acquired certain oil and gas properties in exchange for 1,000,000 shares of our common stock valued at $320.

Shortly thereafter, we acquired ETC, in exchange for an aggregate of 1,000,000 shares of our common stock valued at $250. In March 2009, we formed Miller Energy GP and in April 2009 we formed Miller Energy Income 2009-A, LP (“MEI”). MEI was organized to provide the capital required to invest in various types of oil and gas ventures including the acquisition of oil and gas leases, royalty interests, overriding royalty interests, working interests, mineral interests, real estate, producing and non-producing wells, reserves, oil and gas related equipment including transportation lines and potential investments in entities that invest in such assets (except for other investment partnerships sponsored by affiliates of MEI). Through a subsidiary we own 1% of MEI, however due to the shared management of our company and MEI, we consolidate this entity.

The third acquisition significantly expanded our operations, assets, and reserves, and took us into a new geographic area. On December 10, 2009, we acquired 100% of the membership interests in CIE in exchange for four year stock warrants to purchase 3,500,000 shares of our common stock at exercise prices ranging from $0.01 to $2.00 per share and $250 in cash to satisfy certain expenses as well as reimbursement for reasonable out of pocket expenses. Following the transaction, Mr. David Hall was appointed as a member of our Board of Directors and as Chief Executive Officer of CIE.

Immediately prior to our acquisition of CIE, CIE acquired, through a Delaware Chapter 11 bankruptcy proceeding, the former Alaskan operations of Pacific Energy. The purchased operations included the West McArthur River oil field, the West Foreland natural gas field, the Redoubt field and related Osprey offshore platform and Kustatan Production Facility. All of these assets are located along the west side of the Cook Inlet. We also acquired 602,000 acres of oil and gas leases, including 471,474 acres under the Susitna Basin Exploration License as well as completed 3D seismic geology and other production facilities. At

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closing we paid Pacific Energy $2,250 and provided $2,220 for bonds, contract cure payments and other federal and State of Alaska requirements to operate the facilities.
In April 2011, we changed our name to Miller Energy Resources, Inc.
On June 24, 2011, we acquired a 48% minority interest in each of two limited liability companies, Pellissippi Pointe, LLC and Pellissippi Pointe II, LLC for total cash consideration of $400. We have also agreed to indemnify the sellers of the membership interests with respect to their guaranties of the construction loans held by the Pellissippi Pointe entities. On July 12, 2012, we signed a direct guarantee for 55% of the loan obligation outstanding of $5,074 with FSG Bank. As of April 30, 2013, the loan obligation is $4,970 and the liability recorded for the guarantee is $207. The Pellissippi Pointe entities own two office buildings in west Knoxville, Tennessee. In November, 2011, we moved our corporate headquarters into one of these buildings, located at 9721 Cogdill Road, Knoxville, Tennessee. We executed a five-year lease for the space, and with the addition of us, the building is fully occupied by tenants.

ITEM 1A. RISK FACTORS.

In addition to the other information set forth elsewhere in the Form 10-K, you should carefully consider the following known, material risk factors associated with our business, the oil and gas industry in which we operate, and the ownership of our securities. If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected, and holders or purchasers of our securities could lose part or all of their investments. There may be additional risks that are not presently material or known. We may include additional risk factors in the prospectuses for securities we issue in the future.

Risks Related to Our Business

We have a history of operating losses and incurred a net loss in fiscal 2013, 2012 and fiscal 2011. Our revenues are not currently sufficient to fund our operating expenses and there are no assurances we will develop profitable operations.
We reported operating losses of $32,349 in fiscal 2013, $25,085 in fiscal 2012 and $14,592 in fiscal 2011. As a result of the continued expansion of our business during fiscal 2013, our operating expenses presently exceed our revenues. We anticipate that our operating expenses will continue to increase as we continue to develop our operations in both Tennessee and Alaska. We will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our revenues. We have had to borrow money and raise money through issuances of equity in order to fund our operations in the past, resulting in debt costs, interest, and dilution of our existing shareholders' equity. We may have to reduce our expansion efforts if we have not seen an increase in revenues in the next fiscal year, which could also lead to a loss of properties or reserves. There are no assurances that we will be able to significantly increase our revenues or develop profitable operations.
In preparing our consolidated financial statements for the fiscal years 2013, 2012, and 2011, we and our independent public accounting firms identified material weaknesses in our internal control over financial reporting. If we fail to achieve or maintain effective internal control over financial reporting, we may be unable to accurately and timely report our financial results or prevent fraud, and our business, investor confidence and the market price of our shares may be adversely impacted.
In the course of the preparation and audit of our consolidated financial statements for the fiscal years 2013, 2012, and 2011 we and our independent registered public accounting firms identified a number of deficiencies in our internal control over financial reporting, including “material weaknesses” as defined in the standards established by the U.S. Public Company Accounting Oversight Board Standard. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis, and a significant deficiency is a deficiency, or a combination of deficiencies, in internal control over financial reporting that is less severe than a material weakness, but important enough to merit attention by those responsible for oversight of the company's financial reporting.

The material weaknesses identified for the fiscal years 2013, 2012 and 2011 related to a lack of human resources in our accounting and finance departments. In the audit of our consolidated financial statements for fiscal 2013, we and our independent registered public accounting firm determined that enough time had not lapsed since the hiring of additional accounting personnel to provide assurance that the material weakness has been remediated. In remediating the material weakness, we may experience difficulties in integrating new personnel into the accounting department and may identify areas where additional personnel may be required. In an effort to meet the demands of our planned activities in fiscal 2014 and thereafter, we may be required to supplement our staff with more expensive contract and consultant personnel until we are able to hire new employees, if necessary. We further may not be successful in our efforts to enhance our systems, accounting, controls and reporting performance. All of this may have a material adverse effect on our business, results of operations, cash flows and growth plans, on our regulatory and listing status, and on our stock price.

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We are subject to debt costs under the terms of our Credit Facility with Apollo Investment Corporation. Monies borrowed are subject to an interest rate of 18% per annum.

As described later in this Annual Report, in June 2012 we entered into a Loan Agreement with Apollo Investment Corporation, under which a credit facility of up to $100,000 (the "Apollo Credit Facility") was made available to us. At closing, we drew $40,000 under the Apollo Credit Facility, and have drawn $15,000 in subsequent borrowings and $307 in paid-in-kind interest, for a total indebtedness under our Apollo Credit Facility of approximately $55,307. That amount and any other monies borrowed by us bear interest at mezzanine rates and are subject to a make whole premium and prepayment penalties if any prepayments are made prior to June 29, 2016. These debt costs may be substantial, and will adversely impact our results until the facility has been repaid.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.

The Apollo Credit Facility contains a number of significant covenants that, among other things, restrict our ability to:

- pay for general and administrative expenses;
- deviate from the Approved Plan of Development ("APOD");
- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

Because we are limited in the total amount we may spend on general and administrative expenses, we may need to make reductions in general and administrative expenses in future periods, which could impact our ability to operate our business and achieve our aggressive plan for development.

The Apollo Credit Facility further establishes priorities among the projects we may choose to fund using either loan proceeds or our ordinary collections in the APOD. This may constrain management's ability to pursue projects in their optimal order, or require us to obtain waivers or consents from our lenders in order to deviate from the APOD.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under the Apollo Credit Facility.

If we fail to meet financial and production covenants contained in the Apollo Credit Facility, we may be limited in our ability to make additional borrowings under the Apollo Credit Facility, obtain additional funds on favorable terms, make capital expenditures, withstand a downturn in our business or the economy, or pay dividends on our Series B and Series C Preferred Stock. If the failure to meet these covenants results in a default, we could face the acceleration of our indebtedness under the Apollo Credit Facility which would become immediately due and payable.

The Apollo Credit Facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition and oil and gas production-level tests. Our ability to comply with these ratios and financial condition and production-level tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition and production-level tests. These financial ratio restrictions and financial condition and production-level tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A decline in oil and natural gas prices, a prolonged period of oil and natural gas prices at lower levels, or any event which limits our ability to meet oil and gas production requirements specified in the Apollo Credit Facility could eventually result in our failing to meet one or more of the financial and production-level covenants required by the Apollo Credit Facility, which could require us to raise additional capital at an inopportune time or on terms not favorable to us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition or production-level tests could result in a default under the Apollo Credit Facility. A default under that facility, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit agreement. The accelerated debt would become

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immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. During fiscal 2013, we sought amendments to the Apollo Credit Facility to revise the dates on which the covenant tests would commence, and paid waiver fees up to $200. If, in the future, we are required to obtain similar amendments as a result of our inability to meet the required financial ratios, there can be no assurance that those amendments will be available on commercially reasonable terms or at all.

Based on our production levels existing at April 30, 2013, we would not achieve compliance with the production covenant under the Apollo Credit Facility as of October 31, 2013, the next relevant testing date. Our ability to meet this covenant by that date will depend on new sources of production coming online subsequent to April 30, 2013, including production from RU-2A, which was brought online in June 2013. No assurance can be made regarding RU-2A's continued output in the future or the success of our efforts to increase production from other wells.

Material differences between the estimated and actual timing of critical events may affect the completion and commencement of production from our projects.

We have identified and budgeted for numerous drilling locations, but we may not be able to drill those locations within our expected time frame or at all. Our projects may be delayed by the availability of third-party rigs, project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, equipment repairs, the availability of sufficient capital resources, and other unforeseen events. Delays and differences between estimated and actual timing of critical events may adversely affect our production and our projected cash flows from operations.

We are party to several lawsuits seeking millions of dollars in damages against us. An adverse decision in any of these lawsuits could result in our being forced to pay the prevailing plaintiff substantial amounts of money that would adversely impact our ability to continue with our development plans and/or operate our business.

As described later in this Annual Report, we are subject to lawsuits seeking millions of dollars in damages against us. While we believe these suits to be of an essentially frivolous nature, litigation is inherently unpredictable, and any damages that could ultimately be paid by us in relation to any of these lawsuits are subject to significant uncertainty. The timing and progression of each case is also unpredictable; it may take years for the case to make its way to trial and through various appeals. The total amounts that will ultimately be paid by us in relation to all obligations relating to these lawsuits are subject to significant uncertainty and the ultimate exposure and cost to us will be dependent on many factors, including the time spent litigating each case and the attorneys' fees incurred by us in defending the cases, and whether our insurance provides coverage for the claims asserted in each case. Our consolidated financial statements contained herein do not contain any reserves for any potential damages associated with this pending litigation. If we should not be successful in our defense of this pending litigation, our results of operations in future periods could be materially adversely impacted.

CIE's operations are subject to oversight by the Alaska DNR. CIE's oil and gas leases could be terminated if it fails to uphold the terms of the Assignment Oversight Agreement. If the leases were terminated, we would be unable to continue our operations as they are presently conducted. The Assignment Oversight Agreement, along with the Performance Bond Agreement for the Redoubt Unit and Redoubt Shoal Field, also impose significant bonding requirements on us, which could adversely impact our ability to increase our revenues in future periods.

As a condition of the assignment of certain leases, CIE entered into the Assignment Oversight Agreement with the Alaska DNR effective November 5, 2009. The terms of the agreement require CIE to meet certain funding thresholds and report to the Alaska DNR regularly, until the Alaska DNR determines that CIE has completed its development and operation obligations under the leases. Should CIE fail to submit the information required under the agreement, or spend funds for items or activities that do not support core oil and gas activity as set out in the Plan of Operations or Plan of Development for the leases, the Alaska DNR could choose to terminate the leases.

Additionally, on March 11, 2011, CIE entered into a Performance Bond Agreement with the DNR concerning certain bonding requirements initially established by the Assignment Oversight Agreement. The performance bond, which is set at $18,000, is intended to ensure that CIE has sufficient funds to meet its dismantlement, removal and restoration obligations pertaining to the Redoubt Unit and Redoubt Shoal Field. The Agreement includes a funding schedule, which requires payments annually on July 1, beginning in 2013, of amounts ranging from $1,000 to $2,500 per year, and totaling $12,000, as approximately $6,800 was funded by the previous owner. If CIE is more than 10 days late with a payment to the State Trust Account or more than 10 days late providing proof of a payment into a private account, the State will assess a late payment fee of $50. Our obligation to fund the bond beginning in July 2013 will adversely impact our cash resources available to devote to the expansion of our operations. If we must pay one or more late payment fees, it will further reduce the cash resources we have available to devote to the expansion of our operations and could adversely impact our ability to increase our revenues in future periods.

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We may be subject to regulatory actions surrounding the filing of the 2011 Form 10-K

On July 30, 2011, the Audit Committee of our Board of Directors determined that our consolidated balance sheet at April 30, 2011, and our consolidated statements of operations, stockholders' equity and cash flows for the year then ended (collectively, the "2011 Financial Statements"), as well as the report of KPMG LLP dated July 29, 2011 on such statements, all as included in our 2011 Form 10-K, should not be relied upon. The 2011 Form 10-K was filed with the SEC on July 29, 2011 prior to KPMG LLP completing its audit of the 2011 consolidated financial statements and issuing their independent accountants' report thereon, or issuing its consent to the use of their report. We received a request from the SEC for a more detailed explanation regarding the specific circumstances that led to the filing of the 2011 Form 10-K that included the audit report and consent from KPMG LLP prior to the completion of their audit. In September 2011, we provided the requested explanation to the SEC and are fully cooperating with the staff. We cannot predict the nature of any additional responses or actions that may be required of us surrounding the filing of the 2011 Form 10-K. Such responses could divert management's time and attention from the operation of our business and could result in increased legal fees and fines.

We may fail to fully identify potential problems related to acquired businesses or assets, or obtain protection from the sellers, and the integration of significant acquisitions may be difficult.

Our business plan contemplates significant acquisitions of reserves, properties, prospects, and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are not entitled to contractual indemnification for environmental liabilities and acquired properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating, and integrating significant acquisitions and strategic transactions;
- our ability to meet the reporting requirements under federal securities laws due to the condition or availability of the target's financial records;
- the challenge and cost of integrating acquired operations, accounting, internal controls, human resources, information management, administrative, and other technology systems, and business cultures with our own while carrying on our ongoing business;
- the adjustment to operating a larger combined organization once integrations are complete;
- failure to realize expected synergies and cost savings;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially adversely affected.

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Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on the acreage.
A sizeable portion of our acreage is currently undeveloped. Unless production is established on these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.
Our Susitna Basin Exploration Licenses require us to fulfill certain work commitments and convert acreage to leases in order to retain the acreage after the term of the license.
Over 580,000 acres of our total acreage consists of the three Susitna Basin Exploration Licenses in Cook Inlet, Alaska. These three licenses require us to spend a total of $3,250 in work commitments before we may convert the licenses into leases. We may not be able to complete our work commitments in a timely manner, or if we do complete them, we may not identify any acreage that we would convert to leases. This could result in a substantial decrease in our total acreage in the Cook Inlet Basin.
The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Approximately 79% of our total estimated proved reserves at April 30, 2013 were proved undeveloped reserves. In addition, there are no assurances that probable and possible reserves will be converted to proved reserves.
Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in our reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves, and we typically hold most or all of the working interests in our wells, so must bear most or all of the costs of development ourselves. Although cost and reserve estimates attributable to our natural gas and crude oil reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. We also have a significant amount of unproved reserves at April 30, 2013. There is significant uncertainty attached to unproved reserve estimates, which include probable and possible reserves. Proved reserves are more likely to be produced than probable reserves and probable reserves are more likely to be produced than possible reserves. There are no assurances that we can develop probable or possible reserves into proved reserves, or that if developed, these reserves will become producing reserves to the level of the estimates.
The results of our use of horizontal drilling in Tennessee using long laterals and modern completion techniques are subject to more uncertainties than our vertical drilling programs and may not meet our expectations for reserves or production.
During fiscal 2013, we believe we became the first company to drill horizontal oil wells in the Fort Payne formation in Tennessee. Part of our drilling strategy in formations where we have drilled horizontal wells involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have been used in other basins by other operators. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date is relatively limited and there is no way at this time to determine whether the use of these techniques will prove to be commercially successful in the formations of interest in Tennessee.
Our commodity price risk management and trading activities may prevent us from benefiting fully from price increases and may expose us to the risk of financial loss.
To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
-

- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Our business depends on oil and natural gas transportation facilities, most of which are owned by others.

The marketability of our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. The lack of availability of these facilities for an extended period of time could negatively affect our revenues. Federal and state regulation of oil and natural gas production and

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transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The majority of our oil production is dedicated to one customer and as a result, our credit exposure to this customer is significant.

We have entered into an oil marketing agreement with Tesoro Refining and Marketing Company under which Tesoro purchases all of our oil production in Alaska. We generally do not require letters of credit or collateral to support these trade receivables. Accordingly, a material adverse change in their financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

The majority of our reserves and assets, including our Cook Inlet Basin leases and our Osprey Platform, are located in a region of active volcanoes and we could be subject to the adverse impacts of natural disasters or other regional events.

The Cook Inlet region contains active volcanoes, including Augustine Volcano, Mount Spurr and Mount Redoubt, and volcanic eruptions in this region have been associated with earthquakes and tsunamis. Debris avalanches have also resulted in tsunamis. In 2009, the CIPL suspended operations on several occasions as a result of the spring 2009 major eruption of Mount Redoubt which also resulted in a shutdown of the Drift River Oil Terminal. Our operations in this area are subject to all of the inherent risks associated with operations in a geographical region which is subject to natural disasters and we are susceptible to the risk of damage to our operations and assets located in the Cook Inlet Basin. While our facilities are engineered to withstand seismic activity, and the current tight line configuration should allow us to continue shipments through an active volcanic period without much interruption, we do not maintain business interruption insurance which could adversely impact our results of operations as the result of lost revenues in future periods.

The majority of our oil and gas reserves are located in the Cook Inlet Basin. Any regional events, including price fluctuations, the natural disasters mentioned above, restrictive laws or regulations that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified.

Disruptions in the financial markets could affect our ability to obtain financing on reasonable terms and have other adverse effects on us and the market price of the Series C Preferred Stock.

Over the last several years, the United States stock and credit markets have experienced significant price volatility, dislocations and liquidity disruptions, which have caused market prices of many stocks and debt securities to fluctuate substantially and the spreads on prospective debt financings to widen considerably. More recently, the financial crisis in Europe (which relates primarily to concerns that certain European countries may be unable to pay their national debt) has had a similar, although less pronounced, effect. These circumstances have materially impacted liquidity in the financial markets, making terms for certain financings less attractive and in certain cases have resulted in the unavailability of certain types of financing. Unrest in certain Middle Eastern countries and the resultant increase in petroleum prices have added to the uncertainty in the capital markets. Such uncertainty will lead to continued volatility in the stock and credit markets and may negatively impact our ability to access additional financing at reasonable terms. A prolonged downturn in the stock or credit markets may cause us to seek alternative sources of potentially less attractive financing. These types of events in the stock and credit markets may make it more difficult or costly for us to raise capital through the issuance of our common stock, preferred stock or debt securities. These disruptions may have a material adverse effect on the market value of our common stock and preferred stock, including the Series C Preferred Stock, the return we receive on our investments, as well as other unknown adverse effects on us or the economy in general.

Risks Related to the Oil and Natural Gas Industry

Estimates of oil and natural gas reserves are inherently imprecise. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices and expenditures for future development drilling and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development drilling and exploration activities and prices of oil and natural gas. Actual future production, revenue, taxes, development drilling expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein.

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We may not realize an adequate return on wells that we drill.
Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The wells we drill or participate in may not be productive, and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors including, without limitation:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts, and surface cratering;
- marine risks such as capsizing, collisions, or adverse weather conditions; and
- increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Future drilling activities may not be successful, and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.
Oil and gas prices fluctuate due to a number of uncontrollable factors, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.
Oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, changes in global supply and demand for oil and gas, the actions of the Organization of Petroleum Exporting Countries, the level of global oil and gas exploration and production activity, weather conditions, technological advances affecting energy consumption, domestic and foreign governmental regulations and tax policies, proximity and capacity of oil and gas pipelines and other transportation facilities.
Additionally, a decline in future oil and natural gas prices and the related reduction in revenues could precipitate a breach in the interest coverage ratio covenant contained in our Loan Agreement with Apollo.
Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.
The production rate from oil and gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through exploration and development activities or, through engineering studies, identify additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase.
The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated natural gas, crude oil and natural gas liquids reserves.
You should not assume that the present value of future net revenues from our proved reserves referred to in this Annual Report is the current market value of our estimated natural gas, crude oil and natural gas liquids reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held constant for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In

addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily an appropriate discount factor for determining a market valuation. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the relevance of the 10% discount factor.

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Our business involves a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures or cement failures, and environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases. Any of these risks can cause substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, regulatory investigations and penalties, suspension of our operations and repair and remediation costs. In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease. We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

We face strong industry competition that may have a significant negative impact on our results of operations.

Strong competition exists in all sectors of the oil and gas exploration and production industry. We compete with major integrated and other independent oil and gas companies for acquisition of oil and gas leases, properties, and reserves, equipment, and labor required to explore, develop, and operate those properties, and marketing of oil and natural gas production. Crude oil and natural gas prices impact the costs of properties available for acquisition and the number of companies with the financial resources to pursue acquisition opportunities. Many of our competitors have financial and other resources substantially larger than we possess and have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as fluctuating worldwide commodity prices and levels of production, the cost and availability of alternative fuels, and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. These competitive pressures may have a significant negative impact on our results of operations.

Our industry is subject to extensive environmental regulation that may limit our operations and negatively impact our production. As a result of increased enforcement of existing regulations and potential new regulations following the Gulf of Mexico oil spill, the costs for complying with government regulation could increase.

Extensive federal, state, and local environmental laws and regulations in the United States affect all of our operations. Environmental laws to which we are subject in the U.S. include, but are not limited to, the Clean Air Act and comparable state laws that impose obligations related to air emissions, the RCRA, and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from our facilities, the CERCLA and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which our hazardous substances have been transported for disposal, and the Clean Water Act, and comparable state laws that regulate discharges of wastewater from our facilities to state and federal waters. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental laws, including CERCLA and analogous state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Environmental legislation may require that we do the following:

- acquire permits before commencing drilling;

- restrict spills, releases or emissions of various substances produced in association with our operations;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;
- take reclamation measures to prevent pollution from former operations;
- take remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remedying contaminated soil and groundwater; and
- take remedial measures with respect to property designated as a contaminated site.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas and other petroleum products, air emissions and water discharges related to our operations, and historical industry

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operations and waste disposal practices. The costs of any of these liabilities are presently unknown but could be significant. We may not be able to recover all or any of these costs from insurance. In addition, we are unable to predict what impact the Gulf oil spill will have on independent oil and gas companies such as our company. For instance, companies such as ours currently pay an $0.08 per barrel tax on all oil produced in the U.S. which is contributed to the Oil Spill Liability Trust Fund. There are pending proposals to raise this tax to $0.18 to $0.25 per barrel. It is also probable that there will be increased enforcement of existing regulations and adoption of new regulations which will also increase our cost of doing business which would reduce our operating profits in future periods.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, FERC has authority to impose penalties for violations of the Natural Gas Act, up to $1 per day for each violation and disgorgement of profits associated with any violation. FERC has recently proposed and adopted regulations that may subject our facilities to reporting and posting requirements. Additional rules and legislation pertaining to these and other matters may be considered or adopted by FERC from time to time. Failure to comply with FERC regulations could subject us to civil penalties.

Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post collateral (commonly referred to as “margin”) for such transactions. The Act provides for a potential exception from these clearing and collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. We expect to qualify as a commercial end-user. As required by the Dodd-Frank Act, the Commodities Futures and Trading Commission ("CFTC") has promulgated numerous rules to define these terms. In addition, it is possible that the CFTC, in conjunction with prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral.

We use derivative instruments with respect to a portion of our expected crude oil and natural gas production in order to reduce the impact of commodity price fluctuations and enhance the stability of cash flows to support our capital investment programs and acquisitions. Our current derivative contracts do not require the posting of margin up to $15,000.

Depending on the rules and definitions adopted by the CFTC and prudential regulators, we could be required to post significant amounts of collateral with our dealer counterparties for derivative transactions. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and also cause us to incur additional debt and/or reduce capital investment. In addition, the final CFTC rules may also require the counterparties to our derivative instruments to move some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase our operating and capital costs.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing, or are considering doing so. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in very tight formations.

Although it is not possible at this time to predict the final outcome of the legislation regarding hydraulic fracturing, any new federal, state, or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions in the U.S.

The effects of future environmental legislation on our business are unknown but could be substantial. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Changes in, or enforcement of, environmental laws may result in a curtailment of our production activities, or a material increase in the costs of production, development drilling or exploration, any of which could have a material adverse effect on our financial condition and results of operations or prospects. In addition, many countries, as well as several states in the United States have agreed to regulate emissions of “greenhouse gases.”

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Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for products in the future.

The proposed U.S. federal budget for fiscal year 2014 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On April 10, 2013, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2014. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions eliminate of the ability to fully deduct intangible drilling costs in the year incurred, repeal percentage depletion for oil and natural gas wells, repeal the domestic manufacturing deduction for oil and natural gas companies, increase the geological and geophysical amortization period for independent producers to seven years, repeal the exception to passive loss limitations for working interests in oil and natural gas properties, repeal the enhanced oil recovery credit, and repeal the credit for oil and gas produced from marginal wells. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities. As none of these proposals have yet been voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Risks Related to the Ownership of Our Securities

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We intend to retain any future earnings to fund our operations; therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Also, our credit agreement does not permit us to pay dividends on our common stock. We are prohibited by Tennessee law from paying dividends, if after the payment of the dividend we are unable to pay our debts as they come due in the ordinary course of business, or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed, if we were to be dissolved at the time of the dividend, to satisfy any preferential liquidation rights to those of our common stock.

Certain of our outstanding warrants contain cashless exercise provisions; which means we will not receive any cash proceeds upon their exercise.

At April 30, 2013, we have common stock warrants outstanding to purchase an aggregate of 1,376,650 shares of our common stock with an average exercise price of $5.04 per share which are exercisable on a cashless basis. This means that the holders, rather than paying the exercise price in cash, may surrender a number of warrants equal to the exercise price of the warrants being exercised. It is possible that the warrant holders will utilize the cashless exercise feature which will deprive us of additional capital which might otherwise be obtained if the warrants did not contain a cashless feature.

A large portion of our outstanding common shares are “restricted securities” and we have outstanding options, warrants and purchase rights to purchase approximately 16% of our currently outstanding common stock. The exercise of these options, warrants and purchase rights would be dilutive to our current shareholders, and could adversely affect our stock price.

We may, in the future, issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present shareholders. We are currently authorized to issue 500,000,000 shares of common stock and 150,000 shares of preferred stock with such designations, preferences and rights as determined by our Board of Directors. At July 5, 2013 we had 43,446,694 shares of common stock outstanding together with outstanding options and warrants to purchase an aggregate of 14,503,847 shares of common stock at exercise prices of between $0.01 and $6.94 per share. Of our outstanding shares of common stock at July 5, 2013, approximately 8,169,107 shares are "restricted securities." Future sales of restricted common stock under Rule 144 or otherwise could negatively impact the market price of our common stock. In addition, in the event of the exercise of the warrants and options, the number of our outstanding common stock will increase by approximately 14,503,847, which will have a dilutive effect on our existing shareholders.

The impacts of non-cash gains and losses from derivative accounting in future periods could materially impact our financial results.

To manage variability in cash flows resulting from fluctuation in oil prices, we occasionally enter into commodity derivatives to hedge a portion of our crude oil production. These instruments are marked-to-market on a periodic basis with changes in the estimated fair value recorded to our consolidated statement of operations. As of April 30, 2013, we have a derivative liability of $842. We recognized a non-cash loss on derivatives of $5,235 in fiscal 2013, $3,436 in fiscal 2012 and $1,008 in fiscal 2011. The amount of quarterly non-cash gains or losses we will record in future periods is unknown at this time as the measurement is based upon the fair market value of oil on the measurement date. It is likely, however, that these non-cash gains or losses will continue to have a material impact on our financial results in future periods.

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Substantial stock ownership by our affiliates may limit the ability of our non-affiliate stockholders to influence the outcome of director elections and other matters requiring shareholder approval.
As of April 30, 2013, management and members of the Board of Directors own approximately 30% of our outstanding common stock. Accordingly, they have significant influence in the election of our directors and, therefore, our policies and direction. This concentration of voting power could have the effect of delaying or preventing a change in control or discouraging a potential acquirer from attempting to obtain control of us, which in turn could have a material adverse effect on the market price of our common stock or prevent our shareholders from realizing a premium over the market price for their shares of common stock.
The Change of Control conversion feature of our Series C Preferred Stock may prevent a change in control, or discourage a third party from acquiring us
The Change of Control conversion feature of the Series C Preferred Stock may have the effect of discouraging a third party from making an acquisition proposal for us or of delaying, deferring or preventing certain of our change of control transactions under circumstances that otherwise could provide the holders of our common stock and Series C Preferred Stock with the opportunity to realize a premium over the then-current market price of such stock, or that shareholders may otherwise believe is in their best interests.

Risks Related to the Ownership of our Series C Preferred Stock
The Series C Preferred Stock ranks junior to our Series B Preferred Stock and to all of our indebtedness and other liabilities and is effectively junior to all indebtedness and other liabilities of our subsidiaries.
In the event of our bankruptcy, liquidation, dissolution or winding-up of our affairs, our assets will be available to pay obligations on the Series C Preferred Stock only after all of our indebtedness and other liabilities have been paid. The rights of holders of the Series C Preferred Stock to participate in the distribution of our assets will rank junior to the prior claims of our current and future creditors, to our Series B Preferred Stock and any future series or class of preferred stock we may issue that ranks senior to the Series C Preferred Stock. As of the date hereof, 25,750 shares of Series B Preferred Stock, having a liquidation value of $2,575, are outstanding. In addition, the Series C Preferred Stock effectively ranks junior to all existing and future indebtedness and other liabilities of (as well as any preferred equity interests held by others in) our existing subsidiaries and any future subsidiaries. Our existing subsidiaries are and any future subsidiaries would be separate legal entities and have no legal obligation to pay any amounts to us in respect of dividends due on the Series C Preferred Stock. If we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets to pay amounts due on any or all of the Series C Preferred Stock then outstanding.
We and our subsidiaries have incurred and may in the future incur substantial amounts of debt and other obligations that will rank senior to the Series C Preferred Stock. At April 30, 2013, we had approximately $57,559 of indebtedness, on a consolidated basis (including obligations arising under our Series B Preferred Stock), ranking senior to the Series C Preferred Stock. Our Loan Agreement with Apollo prohibits payments of dividends on the Series C Preferred Stock if we fail to comply with certain financial covenants or, at certain times, if a default or event of default has occurred. Certain of our other existing or future debt instruments may restrict the authorization, payment or setting apart of dividends on the Series C Preferred Stock.
Future offerings of debt or senior equity securities may adversely affect the market price of the Series C Preferred Stock. If we decide to issue debt or senior equity securities in the future, it is possible that these securities will be governed by an indenture or other instruments containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of the Series C Preferred Stock and may result in dilution to owners of the Series C Preferred Stock. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. The holders of the Series C Preferred Stock will bear the risk of our future offerings, reducing the market price of the Series C Preferred Stock and diluting the value of their holdings in us.
We may not be able to pay dividends on the Series C Preferred Stock.

Under Tennessee law, cash dividends may be paid from net earnings only if (1) we would still be able to pay our debts as they become due in the usual course of business after giving effect to the dividend payment, and (2) our total assets are not less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the distribution, to satisfy the preferential rights upon dissolution of shareholders whose preferential rights on dissolution are superior to those receiving the distribution. Our ability to pay cash dividends on the Series C Preferred Stock will require us to be profitable and to have positive net assets (total assets less total liabilities) over our capital. Further, notwithstanding these factors, we may not have sufficient cash to pay dividends on the Series C Preferred Stock. Our ability to pay dividends may be impaired if any of the risks described in this Annual Report, were to occur. In addition, payment of our dividends depends upon our financial condition and other factors as our Board of Directors may deem relevant from time to time. We cannot make assurances that our business will generate sufficient cash flow from operations or that future borrowings will be available to us in an amount sufficient to enable

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us to make distributions on our common stock and preferred stock, including the Series C Preferred Stock, to pay our indebtedness or to fund our other liquidity needs.

The Series C Preferred Stock has not been rated.

We have not sought to obtain a rating for the Series C Preferred Stock. No assurance can be given, however, that one or more rating agencies might not independently determine to issue such a rating or that such a rating, if issued, would not adversely affect the market price of the Series C Preferred Stock. In addition, we may elect in the future to obtain a rating for the Series C Preferred Stock, which could adversely affect the market price of the Series C Preferred Stock. Ratings only reflect the views of the rating agency or agencies issuing the ratings and such ratings could be revised downward, placed on a watch list or withdrawn entirely at the discretion of the issuing rating agency if in its judgment circumstances so warrant. Any such downward revision, placing on a watch list or withdrawal of a rating could have an adverse effect on the market price of the Series C Preferred Stock.

Series C Preferred Stock holders may not be able to exercise conversion rights upon a Change of Control, and, if exercisable, these conversion rights may not adequately compensate you.

Upon the occurrence of a Change of Control, each holder of the Series C Preferred Stock will have the right (unless, prior to the Change of Control Conversion Date, we have provided notice of our election to redeem some or all of the shares of Series C Preferred Stock held by such holder, in which case such holder will have the right only with respect to shares of Series C Preferred Stock that are not called for redemption) to convert some or all of such holder's Series C Preferred Stock into shares of our common stock (or under specified circumstances involving certain alternative consideration).

Although we generally may not redeem the Series C Preferred Stock prior to November 1, 2017, we have a special optional redemption right to redeem the Series C Preferred Stock in the event of a Change of Control, and holders of the Series C Preferred Stock will not have the right to convert any shares that we have elected to redeem prior to the Change of Control Conversion Date.

If we do not elect to redeem the Series C Preferred Stock prior to the Change of Control Conversion Date, then upon an exercise of the applicable conversion rights, the holders of Series C Preferred Stock will be limited to a maximum number of shares of our common stock or other applicable consideration equal to 9.51 multiplied by the number of shares of Series C Preferred Stock converted.

The market price of the Series C Preferred Stock could be substantially affected by various factors.

The market price of the Series C Preferred Stock will depend on many factors, which may change from time to time, including:

- prevailing interest rates, increases in which may have an adverse effect on the market price of the Series C Preferred Stock;
- trading prices of common and preferred equity securities issued by other energy companies;
- the annual yield from distributions on the Series C Preferred Stock as compared to yields on other financial instruments;
- general economic and financial market conditions;
- government action or regulation;
- the financial condition, performance and prospects of us and our competitors;
- changes in financial estimates or recommendations by securities analysts with respect to us, or competitors in our industry;
- our issuance of additional preferred equity or debt securities; and
- actual or anticipated variations in quarterly operating results of us and our competitors.

As a result of these and other factors, investors who purchase the Series C Preferred Stock may experience a decrease, which could be substantial and rapid, in the market price of the Series C Preferred Stock, including decreases unrelated to our operating performance or prospects.

We may issue additional shares of Series C Preferred Stock and additional series of preferred stock that rank on parity with the Series C Preferred Stock as to dividend rights, rights upon liquidation or voting rights.

We are allowed to issue additional shares of Series C Preferred Stock and additional series of preferred stock that would rank equally to the Series C Preferred Stock as to dividend payments and rights upon our liquidation, dissolution or winding up of our affairs pursuant to our amended and restated charter, as amended, and the articles of amendment for the Series C Preferred Stock without any vote of the holders of the Series C Preferred Stock. The issuance of additional shares of Series C Preferred Stock and preferred stock that would rank on parity with the Series C Preferred Stock could have the effect of reducing the amounts

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available to the current holders of our Series C Preferred Stock upon our liquidation or dissolution or the winding up of our affairs. It also may reduce dividend payments to the current holders of the Series C Preferred Stock if we do not have sufficient funds to pay dividends on all Series C Preferred Stock outstanding and other classes of stock with equal priority with respect to dividends.

In addition, although holders of Series C Preferred Stock are entitled to limited voting rights, with respect to such matters, the Series C Preferred Stock will vote separately as a class along with the holders of all other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series C Preferred Stock. As a result, the voting rights of holders of Series C Preferred Stock may be significantly diluted, and the holders of such other series of preferred stock that we may issue may be able to control or significantly influence the outcome of any vote.

Future issuances and sales of preferred stock ranking on parity with the Series C Preferred Stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series C Preferred Stock and our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Holders of Series C Preferred Stock have extremely limited voting rights.

Voting rights as a holder of Series C Preferred Stock are limited. Our shares of common stock are the only class of our securities that carry full voting rights. Voting rights for holders of Series C Preferred Stock exist primarily with respect to the ability to elect, voting together with the holders of any other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series C Preferred Stock, two additional directors to our board of directors, subject to certain limitations, in the event that four quarterly dividends (whether or not consecutive) payable on the Series C Preferred Stock are in arrears, and with respect to voting on amendments to our amended and restated charter, as amended, or articles of amendment relating to the Series C Preferred Stock that materially and adversely affect the rights of the holders of Series C Preferred Stock or authorize, increase or create additional classes or series of our shares that are senior to the Series C Preferred Stock. Other than the limited circumstances described in this Annual Report, holders of Series C Preferred Stock will not have any voting rights.

The Series C Preferred Stock is a relatively new issue of securities and has only a limited trading market, which may negatively affect its value and the ability to transfer and sell shares.

The Series C Preferred Stock is a relatively new issue of securities with only a limited trading market. The volume of trades of shares of the Series C Preferred Stock on the New York Stock Exchange ("NYSE") is often low, and an active trading market on the NYSE for the Series C Preferred Stock may not be maintained in the future and may not provide adequate liquidity. The liquidity of any market for the Series C Preferred Stock that may exist now or in the future will depend on a number of factors, including prevailing interest rates, the dividend rate on our common stock, our financial condition and operating results, the number of holders of the Series C Preferred Stock, the market for similar securities and the interest of securities dealers in making a market in the Series C Preferred Stock. As a result, the ability to transfer or sell the Series C Preferred Stock could be adversely affected.

If the Series C Preferred Stock or our common stock is delisted, the ability to transfer or sell shares of the Series C Preferred Stock may be limited, and the market value of the Series C Preferred Stock will likely be materially adversely affected.

Other than in connection with a Change of Control, the Series C Preferred Stock does not contain provisions that are intended to protect stockholders if our common stock is delisted from the NYSE. Since the Series C Preferred Stock has no stated maturity date, stockholders may be forced to hold their shares of the Series C Preferred Stock and receive stated dividends on the Series C Preferred Stock when, and if authorized by our board of directors and paid by us with no assurance as to ever receiving the liquidation value thereof. In addition, if our common stock is delisted from the NYSE, it is likely that the Series C Preferred Stock will be delisted from the NYSE as well. Accordingly, if the Series C Preferred Stock or our common stock is delisted from the NYSE, the ability to transfer or sell shares of the Series C Preferred Stock may be limited and the market value of the Series C Preferred Stock will likely be materially adversely affected.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 3. LEGAL PROCEEDINGS.

The information set forth in Note 9 - Litigation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable to our operations.

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PART II

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

During fiscal 2013, our common stock, par value $0.0001 per share, was listed on the NYSE under the symbol "MILL." From May 6, 2010 to April 11, 2011, our common stock was listed on the NASDAQ Global Market. Previously, our common stock was quoted on the OTC Bulletin Board and in the over the counter market on the Pink Sheets. The table below provides certain information regarding our common stock for fiscal 2013 and 2012. Prices were obtained from The New York Stock Exchange, Inc. Composite Transactions Reporting System. The quotations reflect inter-dealer prices, without retail mark-up, markdown or commission, and may not represent actual transactions. Per-share prices shown below have been rounded to the indicated decimal place.

	2013		2012	
	High	Low	High	Low
First quarter	$5.29	$3.75	$8.02	$4.41
Second quarter	5.26	3.79	3.95	2.16
Third quarter	5.01	3.38	4.04	2.63
Fourth quarter	4.23	3.50	5.47	3.90

The closing price of our common stock, as reported on the New York Stock Exchange for July 5, 2013, was $4.02 per share. As of July 5, 2013, there were 43,446,694 shares of our common stock outstanding held by approximately 341 stockholders of record and approximately 11 beneficial owners.

We have never paid cash dividends on our common stock and we do not anticipate that we will declare or pay dividends in the foreseeable future. Payment of dividends, if any, is within the sole discretion of our Board of Directors and will depend, among other factors, upon our earnings, capital requirements and our operating and financial condition. In addition under Tennessee law, we may not pay a dividend if, after giving effect, we would be unable to pay our debts as they become due in the usual course of business or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the payment of the dividend to satisfy the preferential rights upon dissolution of shareholders whose preferential rights were superior to those receiving the dividend. In addition, our credit facility with Apollo does not permit us to pay dividends on our common stock.

Information concerning securities authorized for issuance under equity compensation plans is set forth in the proxy statement relating to our fiscal 2013 annual meeting of stockholders, which is incorporated herein by reference.

Stockholder Return Performance Presentation

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of our common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from April 30, 2009, through April 30, 2013. The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Miller Energy Resources, Inc., S&P 500 Index
and the Dow Jones US Exploration & Production Index

	2008	2009	2010	2011	2012	2013
Miller Energy Resources, Inc.	$100	$330	$5,780	$5,770	$5,430	$3,800
S&P's Composite 500 Stock Index	100	63	86	98	101	115
Dow Jones US Exploration & Production Index	100	52	76	100	86	94

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ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth selected financial data of our company over the five-year period ended April 30, 2013, which information has been derived from our audited financial statements. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth in Part IV, Item 15 of this Form 10-K.

	As of or for the Year Ended April 30,				
	2013	2012	2011	2010	2009
Income Statement Data:					
Total revenues	$34,801	$35,402	$22,842	$5,867	$1,567
Net income (loss) attributable to common stockholders	(25,495)	(19,537)	(3,880)	250,941	8,356
Net income (loss) per common share:					
Basic	(0.60)	(0.48)	(0.11)	11.65	0.56
Diluted	(0.60)	(0.48)	(0.11)	8.34	0.56
Balance Sheet Data:					
Total assets	$575,405	$536,389	$509,081	$500,342	$9,942
Total debt	57,559	24,130	2,000	1,239	1,959
Weighted average common shares outstanding:					
Basic	42,682,685	40,811,308	36,112,286	21,537,677	14,827,877
Diluted	42,682,685	40,811,308	36,112,286	30,092,017	14,827,877

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and accompanying notes included herein and in our most recent Annual Report on Form 10-K, as amended.

Executive Overview

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration, development and operation of oil and gas wells in the Appalachian region of east Tennessee and in southcentral Alaska. Occasionally, during times of excess capacity, we offer these services on a contract basis to third-party customers primarily engaged in our core competency - natural gas exploration and production.

Strategy

Our mission is to grow a profitable exploration and production company for the long-term benefit of our shareholders by focusing on the development of our reserves, continued expansion of our oil and natural gas properties and increasing our production and related cash flow. We intend to accomplish these objectives through the execution of our core strategies, which include:

- Develop Acquired Acreage. We will focus on organically growing production through drilling for our own benefit on existing leases and acreage in the exploration licenses with a view towards retaining the majority of working interest in the new wells. This strategy will allow us to maintain operational control, which we believe will translate to long-term benefits;
- Increase Production. We plan on increasing oil and gas production through the maintenance, repair and optimization of wells located in the Cook Inlet region and development of wells in the Appalachian region of east Tennessee. Our operational team will employ a combination of the latest available technologies along with tried and true technologies to restore as well as explore and develop our properties;
- Expand Our Revenue Stream. We intend to fully exploit our mid-stream facilities, such as our injection wells and the Kustatan Production Facility, our ability to engage in the commercial disposal of waste generated by oil and gas operations, our capacity to process third party fluids and natural gas and to offer excess electrical power to net users in the Cook Inlet region; and
- Pursue Strategic Acquisitions. We have significantly increased our oil and gas properties through strategic low-cost / high-value acquisitions. Under the same strategy, our management team will continue to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We plan to leverage our management team's expertise to pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

Our management team is focused on maintaining the financial flexibility required to successfully execute these core strategies.

Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations. We will focus on adding reserves through new drilling, well workovers and recompletions of our current wells. Additionally, we will seek to grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing oil and natural gas reserves that are suitable for us.

Financial and Operating Results

We continued to utilize operational cash flow along with funds from our credit facility and funds raised from sales of our Series C Preferred Stock made in two "best efforts" public offerings and in "at-the-market" public offerings to support our capital expenditures during fiscal 2013. For the fiscal year ended April 30, 2013, we reported notable achievements in several key areas. Highlights for the period include:

- On June 29, 2012, we fully redeemed the outstanding Series A Preferred Stock.
- On June 29, 2012, we closed our new credit facility with Apollo Investment Corporation and repaid our Guggenheim Credit Facility. For additional information refer to Note 3 - Debt, in the consolidated financial statements.

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- Rig 34 was mobilized to the Otter natural gas prospect and the drilling phase was completed at a depth of 5,680 feet in the Beluga formation. Mud logs have reported two significant hydrocarbon gas shows in the zone of interest. Additional work is now needed to fully evaluate the Beluga formation. Our engineering team is currently finalizing plans to deepen the Otter well #1 a minimum of 900 feet and a maximum of 1,300 feet. Another 900 feet will fully penetrate the Beluga formation leading us immediately into the Tyonek formation.
- On August 21, 2012, we gained approval from state regulators to commence drilling with Rig 35 on the Osprey offshore platform. The rig has been used on workovers for RU-1, RU-3 and RU-7 and sidetracking a new RU-2A. With subsequent work, RU-3 and RU-4 are now fulfilling 100% of our current fuel gas demand with a combined flow rate around 2.5 MMcfd.
- On September 21, 2012, we entered into a Special Warrant Exercise Agreement with warrant holders, pursuant to which warrant holders agreed to exercise 586,001 warrants immediately for $4.00 per share and waived their right to a cashless exercise. We received net proceeds of $2,291 upon exercise of these warrants.
- Also on September 21, 2012, we entered into a Bristol Warrant Exercise Agreement with Bristol Capital, LLC, pursuant to which Bristol Capital, LLC agreed to exercise 300,000 warrants immediately for $4.00 per share and for cash. We received net proceeds of $1,200 upon exercise of these warrants.
- On September 24, 2012, we issued 25,750 shares of a new class of Series B Preferred Stock to 10 accredited investors in a private offering exempt from registration under the Securities Act of 1933, as amended. We received net proceeds of $2,408 in connection with this sale. For additional information refer to Note 3 - Debt, in the consolidated financial statements.
- On October 5, 2012, we issued 685,000 shares of a new class of Series C Preferred Stock in a public sale pursuant to a prospectus supplement date September 18, 2012 (issued under our existing S-3 registration statement, filed with the SEC as file number 333-183750). This new series of stock is listed for trading on the NYSE under the ticker symbol MILLprC. We received net proceeds of $14,420 in connection with this sale.
- On October 12, 2012, we entered into the ATM Agreement with MLV for the placement and sale of our common stock and Series C Preferred Stock in one or more "at the market" public offerings from time to time. The first sale made pursuant to this agreement occurred on November 1, 2012, as discussed below.
- On October 26, 2012, we completed a workover on the RU-1 well in the Redoubt Shoals field in Alaska. The workover involved replacing a failed electric submersible pump as well as removing other downhole obstructions. We initially capitalized the cost of the workover as we believed the workover would significantly increase our access to proved reserves. We ultimately concluded it should be expensed as the workover did not significantly increase our access to proved reserves. The costs of the workover were written off during the fourth quarter.
- Starting on November 1, 2012, and periodically during the quarter, we issued 95,048 shares of our Series C Preferred Stock in "at-the-market" offerings pursuant to the ATM Agreement and a prospectus supplement dated October 12, 2012 (issued under our existing S-3 registration statement, filed with the SEC as file number 333-183750). These sales were made at an average price on the date of such sale ranging from $22.00 to $23.00 per share. We received net proceeds of $2,044 in connection with these sales.
- On November 26, 2012, we applied for a right-of-permits necessary for construction of the Trans Foreland pipeline. When completed, this undersea pipeline will move our crude from the west side of the Cook Inlet where we have several producing units to the east side where the nearest refinery is located. Transporting the crude this way will be cheaper and safer than using tankers which is our only current option.
- On January 11, 2013, we completed the first horizontal well in the Mississippian Lime in Tennessee, CPP-H-1. The well was drilled into the Fort Payne Formation to a true vertical depth of approximately 1,600 feet on our Cumberland Plateau Partners LLC lease in Scott County, Tennessee, and it exposed a pay section of approximately 2,300 feet in the horizontal section of the well.
- On January 26, 2013, we brought a new gas well, RU-4A, into production on the Osprey platform. The workover consisted of re-completing the well to access a behind pipe gas accumulation in the Lower Tyonek gas sands at a measured depth of approximately 9,200 feet.
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On February 7, 2013, we borrowed an additional $5,000 under our new credit facility with Apollo Investment Corporation. For additional information refer to Note 3 - Debt, in the consolidated financial statements.

- On February 15, 2013, we issued 625,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement date February 13, 2013 and we received net proceeds of $13,325 in connection with the issuance.
- On February 25, 2013, we brought a new gas well, RU-3, into production on the Osprey platform. The workover consisted of re-completing the well to access a behind pipe gas accumulation in the Lower Tyonek gas sands at a measured depth of approximately 14,800 feet.

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- On April 17, 2013, we borrowed an additional $10,000 under our new credit facility with Apollo Investment Corporation. For additional information refer to Note 3 - Debt, in the consolidated financial statements.

Fiscal 2014 Outlook

As we head into fiscal 2014, we believe our inventory of recompletion, workovers, and exploration and development projects offers numerous growth opportunities. Subsequent to April 30, 2013, we brought RU-2A online after using Rig 35 to complete a sidetrack. We are currently using Rig 35 to work on a sidetrack at RU-1 and expect to complete the sidetrack during the summer of 2013. Upon completion of the sidetrack, we will work on recompletion of RU-5. We also have several development projects onshore, which we expect will also contribute to production in fiscal 2014, along with the offshore wells brought online subsequent to April 30, 2013. No assurance can be made regarding the success of these development and recompletion efforts. Our current 2014 capital budget is $125,000. The majority of this budget is expected to be spent on projects in Alaska, with the remaining amount allocated to our Appalachian region. Due to the uncertainty associated with changes in commodity prices, we closely monitor our cost levels and revise our capital budgets based on changes in forecasted cash flows. This means our plan for capital expenditures may change as a result of anticipated changes in the market place. Further, our ability to fully utilize the budget will be dependent on a number of factors including, but not limited to, access to capital, weather and regulatory approval.

We note that, although we expect to continue to sell our Series C Preferred Stock in additional “at-the-market” offerings during fiscal 2014, we cannot guarantee that market conditions will continue to permit such sales at prices we would find acceptable. If that occurred, cash generated from those offerings would cease.

We expect to fund a portion of our remaining 2014 capital budget with free cash flow from operations, state of Alaska tax credits, potential joint ventures, and through debt, equity and preferred equity capital markets. On May 10, 2013 and on July 2, 2013, we closed two other offerings of our Series C Preferred Stock. For additional information on these offerings, refer to Note 15 - Subsequent Events, in the consolidated financial statements. In the event we are unable to raise additional capital on acceptable terms, we may reduce our capital spending.

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Results of Operations

Revenues

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Oil revenues:					
Cook Inlet	$27,891	(9)%	$30,566	57%	$19,459
Appalachian region	1,556	18	1,314	46	901
Total	$29,447	(8)	$31,880	57	$20,360
Natural gas revenues:					
Cook Inlet	$41	(69)	$134	(53)	$286
Appalachian region	427	(11)	479	9	440
Total	$468	(24)	$613	(16)	$726
Other revenues:					
Cook Inlet	$3,950	226	$1,212	61	$753
Appalachian region	936	45	1,697	69	1,003
Total	4,886	68	2,909	66	1,756
Total revenues	$34,801	(2)	$35,402	55	$22,842

Net Production

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Oil volume - bbls:					
Cook Inlet	275,658	(15)%	325,756	28%	254,504
Appalachian region	19,825	19	16,655	17	14,292
Total	295,483	(14)	342,411	27	268,796
Natural gas volume[1]- mcf:					
Cook Inlet	7,500	(84)	45,985	8	42,480
Appalachian region	125,238	(4)	130,609	19	109,683
Total	132,738	(25)	176,594	16	152,163
Total production[2] - boe:					
Cook Inlet	276,908	(17)	333,420	27	261,584
Appalachian region	40,698	6	38,423	18	32,573
Total	317,606	(15)	371,843	26	294,157

1 Cook Inlet natural gas volume excludes natural gas produced and used as fuel gas.

2 These figures show production on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products.

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Pricing

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Average oil sales price - per barrel:					
Cook Inlet	$102.74	9%	$93.83	23%	$76.46
Appalachian region	83.92	6	78.89	25	63.04
Total	101.53	9	93.10	23	75.75
Average natural gas sales price - per mcf:					
Cook Inlet	3.99	37	2.92	(57)	6.73
Appalachian region	3.41	(7)	3.66	(9)	4.01
Total	3.52	1	3.47	(27)	4.77

Crude Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to the rise in global demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in fiscal 2013 were 9% above fiscal 2012, increasing from an average of $93.10 per bbl in 2012 to $101.53 per bbl in 2013.

Natural Gas Prices

Natural gas is subject to price variances based on local supply and demand conditions. The majority of our natural gas sales contracts are indexed to prevailing local market prices. Average realized prices increased 1% in 2013 compared to 2012.

Crude Oil Revenues

2013 vs. 2012. During 2013, oil revenues totaled $29,447, 8% lower than 2012. The decrease resulted from a 14% decrease in production partially offset by a 9% increase in realized oil prices. Oil revenues represented 85% of our consolidated total revenues in 2013 and 93% of our equivalent production.

Oil production decreased 46,928 bbls, driven by a 50,098 bbls decrease in the Cook Inlet region partially offset by a small increase in the Appalachian region. The production decrease in the Cook Inlet region resulted from wells being off-line during certain portions of the year, a normal decline curve and fluctuations in shipping schedules.

2012 vs. 2011. During 2012, oil revenues totaled $31,880, 57% higher than 2011, driven by a 23% increase in average realized prices and a 27% increase in production. Oil revenues represented 90% of our consolidated total revenue and 92% of our equivalent production in 2012, compared to 89% and 91%, respectively, in the prior year.

Oil production increased 73,615 bbls, driven by a 71,252 bbls increase in the Cook Inlet region, with the Appalachian region contributing an additional 2,363 bbls to the increase in total production for the year. The significant production increase in the Cook Inlet region resulted from bringing wells at our Redoubt Unit online.

Natural Gas Revenues

2013 vs. 2012. During 2013, natural gas revenues totaled $468, 24% lower than 2012. The decrease resulted from a 25% decrease in production. Natural gas represented 1% of our consolidated total revenues and 7% of our equivalent production.

2012 vs. 2011. During 2012, natural gas revenues totaled $613, $113 lower than the 2011 natural gas revenues of $726, driven by a 27% decrease in average realized prices, partially offset by a 16% increase in production. Natural gas represented 2% of our consolidated total revenues and 8% of our equivalent production in 2012, compared to 3% and 9%, respectively, in the prior year.

Other Revenues

2013 vs. 2012. Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling and maintenance and repair of third party wells as well as rental income we receive for services and use of facilities in the Cook Inlet region. During 2013 and 2012, other revenues totaled $4,886, or 14%, and $2,909, or 8%, respectively, of our consolidated total revenues. The increase in other revenues primarily resulted from a road and pad building project in the Cook Inlet region.

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2012 vs. 2011. Other revenues primarily represent revenues generated from contracts for plugging, drilling and maintenance and repair of third party wells as well as rental income we received for use of facilities in the Cook Inlet region. During 2012 and 2011, other revenues totaled $2,909, or 8%, and $1,756, or 8%, respectively, of our consolidated total revenues. The increase in other revenues primarily resulted from an increase in plugging activities in the Appalachian region and a 61% increase in facility rentals and other miscellaneous income in the Cook Inlet region.

Cost and Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and an equivalent unit of production (boe) basis where meaningful.

	For the Year Ended April 30,			For the Year Ended April 30,		
	2013	2012	2011	2013 (Per boe)	2012	2011
Oil and gas operating costs	$24,698	$14,861	$9,703	$65.91	$36.62	$29.61
Cost of other revenues	4,189	926	808	NM	NM	NM
General and administrative	22,799	29,718	14,555	NM	NM	NM
Exploration expense	1,458	1,241	—	NM	NM	—
Depreciation, depletion, and amortization	13,170	13,310	10,961	35.15	32.80	33.45
Accretion of asset retirement obligation	900	1,072	1,407	NM	NM	NM
Other operating expense, net	(64)	(641)	—	NM	NM	NM
Total costs and expenses	$67,150	$60,487	$37,434	$179.20	$149.06	$114.23

NM = not meaningful

Oil and Gas Operating Costs

Oil and gas operating costs increased $9,837 from fiscal 2012, or 66%. The majority of the increase resulted from $7,462 in workover cost related to our RU-1 and RU-7 wells in the Redoubt Shoals field in the Cook Inlet region. In addition, the majority of our operating costs are fixed, and as such, we did not experience a proportionate decrease in cost from current period declines in production. Increased drilling activities and rental of camp facilities and equipment in the Cook Inlet region require additional personnel in our camps, which increase the cost of support services.

Cost of Other Revenues

Our business is primarily focused on exploration and production activities. The cost of other revenues represent costs of services to third parties as a result of excess capacity, and are derived from the direct labor costs of employees associated with these services, as well as costs associated with equipment, parts and repairs. During 2013, we experienced increases in cost of other revenues in the Cook Inlet region as we continued to monetize our midstream capabilities.

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Direct labor	$2,656	292%	$677	57%	$430
Equipment	775	100	—	(100)	41
Repairs	598	572	89	31	68
Insurance	91	100	—	—	—
Other	69	(57)	160	(41)	269
Total	$4,189	352%	$926	15%	$808

During 2013, cost of other revenues increased 352% to $4,189. A substantial portion of this increase is related to direct labor and equipment costs incurred as a result of the road building contract and the grind and inject facility.

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General and Administrative Expenses
General and administrative ("G&A") expenses include the costs of our employees, related benefits, professional fees, travel and other miscellaneous general and administrative expenses.

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Stock-based compensation	$10,132	(28)%	$14,072	175%	$5,126
Professional fees	6,248	37	4,561	36	3,347
Salaries	3,732	12	3,330	29	2,580
Employee benefits	2,357	(38)	3,824	115	1,780
Travel	1,744	3	1,693	115	786
State production credits	(3,268)	100	—	(100)	(873)
Other	1,854	(17)	2,238	24	1,809
Total	$22,799	(23)%	$29,718	104%	$14,555

G&A expenses decreased $6,919 from fiscal 2012, or 23%. Stock-based compensation decreased 28% from the same period in the prior year, predominantly due to significantly less awards granted during our 2013 fiscal year as compared to the previous fiscal year. Further, our stock-based compensation expenses in 2013 were spread over a longer vesting or requisite period than awards granted in our 2012 fiscal year. During 2013, we submitted two Alaska loss carryforward credit applications, which in accordance with our accounting policy, reduced our G&A expense by $3,268. Salaries increased 12% from the same period in the prior fiscal year as we continue to expand our engineering, legal and accounting staff. The increase in professional fees of 37% results from additional cost related to capital markets and investor relations activities.

Exploration Expense
Exploration expense consists of abandonments of drilling locations, exploration licenses, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on unproved properties.

Depreciation, Depletion and Amortization
Depreciation, depletion and amortization (“DD&A”) expenses include the depreciation, depletion and amortization of leasehold costs and equipment. Depletion is calculated on a unit-of-production basis. Depreciation is calculated on a straight-line basis.

	For the Year Ended April 30,					
	2013	2012	2011	2013 (Per boe)	2012	2011
Depletion:						
Cook Inlet region	$8,460	$11,790	$9,703	$26.80	$29.42	$29.86
Appalachian region	1,343	747	773	22.61	19.45	23.73
	9,803	12,537	10,476	26.16	28.55	29.31
Depreciation:						
Cook Inlet region	2,591	169	2	NM	NM	NM
Appalachian region	776	604	483	NM	NM	NM
	3,367	773	485	8.99	1.76	1.36
Total DD&A	$13,170	$13,310	$10,961	$35.15	$30.31	$30.66

The decrease in depletion in the Cook Inlet region is primarily a result of decreased production. The increase in depreciation in the Cook Inlet region is primarily due to Rig 34 and Rig 35 being placed in service during the period.

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Other Income and Expense
The following table shows the components of other income and expense.

	For the Year Ended April 30,				
	2013	Increase (Decrease)	2012	Increase (Decrease)	2011
Interest expense, net	$(4,276)	133%	$(1,837)	97%	$(934)
Gain (loss) on derivatives, net	6,751	338	(2,832)	(181)	(1,008)
Gain on acquisitions	—	—	—	—	6,910
Other income (expense), net	(329)	(667)	58	111	(537)
Total	$2,146	147%	$(4,611)	(204)%	$4,431

Interest Expense, Net
2013 vs. 2012. Interest expense, net of interest income increased $2,439 from fiscal 2012, or 133%, driven primarily by increased outstanding debt as of April 30, 2013, coupled with less capitalized interest recorded during 2013.
2012 vs. 2011. Interest expense, net, increased $903 from 2011, or 97%, driven primarily by a $632 increase in amortization of deferred financing costs. The Company capitalized $3,700 of interest in equipment and oil and gas properties as of April 30, 2012.
Gain (Loss) on Derivatives, Net
We experience earnings volatility as a result of not using hedge accounting to account for changes in commodity prices. As the positions of future oil production are marked-to-market, both realized and unrealized gains or losses are included on our consolidated statements of operations. We do not engage in speculative trading and utilize commodity derivatives only as a mechanism to lock in future prices for a portion of our expected crude oil production.
2013 vs. 2012. During fiscal 2013, unrealized gain on commodity derivatives totaled $5,235, On June 6, 2012, we terminated the commodity derivative contracts in place on April 30, 2012, which were settled against the NYMEX WTI Cushing Index. In consideration of such termination, the counterparty paid the Company settlement value of $4,283 which was recorded as a realized gain. The realized gain was partially offset by realized losses during 2013 to arrive at a net realized gain of $1,516 for the year. Our overall net gain position increased 338% from 2012, primarily as a result of changes in commodity prices and the correlating fair value of our derivatives.
2012 vs. 2011. During 2012, unrealized loss on derivatives totaled $3,436, offset by a net realized gain of $604. Our overall net loss position increased 181% from 2011, primarily as a result of changes in commodity prices. Unrealized net loss on commodity derivatives accounted for $3,436 of the total net loss on derivatives, with the remaining portion related to changes in the fair value of warrants.
Gain on Acquisitions
During 2011, we recorded a gain of $6,910 (inclusive of accrued interest) related to restricted cash held by the State of Alaska that was not previously accounted for as part of the Alaska acquisition in 2010. This amount could not be verified until our entry into the Performance Bond Agreement with the State of Alaska on March 11, 2011. Under the agreement, we are required to post a bond for an aggregate amount of $18,000 with $6,800 restricted cash held by the State to be applied to the total bond requirement. We recorded this event as a gain on acquisition for our Alaska subsidiary.

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Liquidity and Capital Resources

Our cash flows, both in the short-term and long-term, are impacted by highly volatile oil and natural gas prices. Significant deterioration in commodity prices negatively impacts revenues, earnings and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactful as commodity prices in the short-term.

Our long-term cash flows are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. Cash investments are required continuously to fund exploration and development projects and acquisitions, which are necessary to offset the inherent declines in production and proven reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our future liquidity. For a discussion of risk factors related to our business and operations, please refer to the section entitled "Risk Factors" in this Annual Report.

We may elect to utilize additional borrowing capacity under the Apollo Credit Facility when available, proceeds from the sales of both debt and equity in the capital markets, or proceeds from the occasional sale of nonstrategic assets to supplement our liquidity and capital resource needs.

In fiscal 2013, we experienced an operating loss. We anticipate that our operating expenses will continue to increase as we fully develop our assets in the Cook Inlet and Appalachian regions. Although we expect an increase in revenues from these development activities, we will continue depleting our cash resources to fund drilling and workover activities as well as other operating expenses until such time as we are able to significantly increase our revenues above costs.

We believe that the liquidity and capital resource alternatives available to us through the public offerings of additional Series C Preferred Stock, in both “at-the-market” sales and additional underwritten offerings, combined with additions to the borrowing base under our Apollo Credit Facility which may become available, and internally generated cash flows and other potential sources of funds, will be adequate to fund our short-term and long-term operations, including our capital budget, repayment of debt maturities, and any amount that may ultimately be paid in connection with contingencies; however, our Apollo Credit Facility restricts our access to and control of certain bank accounts without compliance with certain provisions of the loan agreement.

The Apollo Credit Facility also contains financial and production covenants. As of April 30, 2013, we were not in compliance with such covenants. However, we received a waiver of such violations from Apollo on July 11, 2013. Under the terms of the waiver, we will be required to maintain compliance with the financial and production covenants on a quarterly basis commencing October 31, 2013. Based on our production levels existing at April 30, 2013, we would likely not achieve compliance with each of the covenants as of October 31, 2013. However, we believe we will sufficiently increase our production levels to enable us to achieve compliance with the financial and production covenants. Much of the increased production is expected to come from the success of RU-2A, which was brought online in June 2013. In addition to RU-2A, we are currently completing a sidetrack on RU-1 that we expect to bring online during the summer of 2013. Once RU-1 is online, we expect to commence with the recompletion of RU-5. We also have several ongoing development projects onshore, which we also expect will contribute to production in fiscal 2014, along with the offshore wells brought online subsequent to April 30, 2013. No assurance can be made regarding the success of these development and recompletion efforts and our ability to meet future financial and production covenants. In the event we do not comply with future financial and production covenants, we would evaluate alternative financing sources including, but not limited to, common or preferred equity offerings, joint ventures, and the financing of receivables.

These restrictions notwithstanding, absent an event of default, the Apollo Credit Facility requires that Apollo release to us funds needed to pay for approved operational activity, subject to certain limitations on the order in which we undertake new projects, and for the payment of certain permitted expenses that arise in the ordinary course of business. The release of funds for other purposes is subject to Apollo's discretion, except that, absent an event of default and so long as at least half of these funds are spent on projects included in our plan of development, we do have the right to use 50% of all proceeds raised from sales of equity securities in excess of $20,000 on such matters as we see fit. We reached this $20,000 threshold on October 5, 2012, the date of the initial public offering of Series C Preferred Stock. The intent of the restrictions in the Apollo Credit Facility on our ability to access cash in our accounts is to require that Company allocate available cash to high-priority projects first and to control spending that is not strongly linked to the development of our existing assets. To date, the restrictions have not impeded our ability to run the business in any way, except that we have requested from time to time that Apollo agree to change the priorities of certain projects on our approved plan of development, to better respond to changing market conditions in the Cook Inlet region. Periodic adjustments to our approved plan of development were contemplated by the terms of the Apollo Credit Facility, and, to date, Apollo has granted our requests when made. We do not anticipate that the restrictions placed on our accounts under the Apollo Credit Facility will interfere with or require any alteration of management's overall plans in the future, subject to the need to make additional adjustments to the approved plan of development as market conditions change.

Pursuant to the September 25, 2012 amendment ("September Amendment") to the Apollo Credit Facility, upon each sale of our Series C Preferred Stock, we have agreed to deposit a portion of the proceeds of the sale into a separate account in an amount

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at least equal to the dividends scheduled to come due on our Series B Preferred Stock and our Series C Preferred Stock on or prior to September 25, 2013. As of April 30, 2013, the balance in this account was $2,110. Although we presently have the right to direct disbursements from this account without Apollo's consent, Apollo has taken a security interest in this account, and the terms of the Apollo Credit Facility state that we may only disburse funds from this account as needed to pay dividends on the Series B Preferred Stock and Series C Preferred Stock. If an event of default were to occur under the Apollo Credit Facility, Apollo would have the right to take control over this account. We have paid cash dividends on the Series B Preferred Stock and the Series C Preferred Stock in accordance with the terms of the Series B Preferred Stock and the Series C Preferred Stock as set forth in our Charter.
Current restricted cash balances include amounts held in escrow to secure company related credit cards. As of April 30, 2013 and 2012, current restricted cash also includes $7,144 and $2,045 of cash temporarily held in an account that is controlled by our lender. Non-current restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, including the possible dismantling of our off-shore platform, and general liability bonds.

Sources and Uses of Cash
The following table presents the sources and uses of our cash and cash equivalents for the periods presented:

	For the Year Ended April 30,		
	2013	2012	2011
Sources of cash and cash equivalents:			
Net cash provided by operating activities	$—	$6,901	$7,734
Proceeds from borrowings, net of debt acquisition costs	51,147	28,754	5,500
Proceeds from sale of equipment	2,000	—	—
Exercise of equity rights	3,832	1,383	1,266
Issuance of preferred stock, net of issuance costs	33,200	10,000	—
	90,179	47,038	14,500
Uses of cash and cash equivalents:			
Net cash used in operating activities	(11,491)	—	—
Cash dividends	(1,231)	—	—
Capital expenditures for oil and gas properties	(26,361)	(7,558)	(10,490)
Purchase of equipment and improvements	(11,533)	(26,409)	(825)
Payments on debt	(24,130)	(8,764)	(3,500)
Redemption of preferred stock	(11,240)	—	—
Increase in restricted cash	(5,613)	(1,895)	(1,121)
	(91,599)	(44,626)	(15,936)
Increase (decrease) in cash and cash equivalents	$(1,420)	$2,412	$(1,436)

Net Cash Provided by Operating Activities
Our sources of capital and liquidity are partially supplemented by cash flows from operations, both in the short-term and long-term. These cash flows, however, are highly impacted by volatility in oil and natural gas prices. The factors in determining operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation ("ARO") accretion, non-cash compensation, and deferred income tax expense, which affect earnings but do not affect cash flows.
Net cash used by operating activities of fiscal 2013 totaled $11,491, down $18,392 from 2012. The decrease resulted primarily from a decrease in revenue coupled with an increase in operating costs.
Proceeds from Credit Facilities and Other Items
As of April 30, 2013, borrowings under our Apollo Credit Facility totaled $55,307, all of which was borrowed under the credit facility during fiscal 2013. In connection with the establishment of the facility, we paid $3,853 in debt

issuance costs. The proceeds were used to repay our Guggenheim Credit Facility and redeem our outstanding Series A Preferred Stock. For additional

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information on the credit facilities, please see Note 3 - Debt in the Notes as set forth in the accompanying consolidated financial statements.

We received proceeds from the sale of a generator totaling $2,000 during the first quarter of fiscal 2013.

On September 24, 2012, we sold 25,750 shares of our Series B Preferred Stock for gross proceeds of $2,575. We paid $167 of issuance costs which have been capitalized and are being amortized over the term of the instrument. The outstanding Series B Preferred Stock is classified as long-term debt, in accordance with Financial Accounting Standards Board Accounting Standards Codification ("ASC") 480 "Distinguishing Liabilities from Equity". See Note 3 - Debt in the Notes as set forth in the accompanying consolidated financial statements.

On September 28, 2012, we sold 685,000 shares of our Series C Preferred Stock for gross proceeds of $15,755. We incurred issuance costs of $1,335, yielding net proceeds of $14,420. The Series C Preferred Stock is classified as temporary equity in accordance with ASC 480 and is being accreted to redemption value through the earliest repayment date of November 1, 2017. See Note 7 - Stockholders' Equity in the Notes as set forth in the accompanying consolidated financial statements.

Starting on November 1, 2012, and periodically during the third and fourth quarters, we issued 144,901 shares of our Series C Preferred Stock in "at-the-market" offerings pursuant to the ATM Agreement and a prospectus supplement dated October 12, 2012 (issued under our existing S-3 registration statement, filed with the SEC as file number 333-183750). These sales were made at an average price on the date of such sale ranging from $22.00 to $23.51 per share. We received net proceeds of $3,112 in connection with these sales.

On February 12, 2013, we sold an additional 625,000 shares of the Series C Preferred Stock at a price of $22.90 per share for gross proceeds of $14,312. We incurred issue costs of $987, yielding net proceeds of $13,260.

We further note that, after the close of the fiscal year, and to date, we have sold an additional (i) 43,180 shares of the Series C Preferred Stock in "at-the-market" offerings, at an average price on the date of such sale ranging from $22.01 to $22.35 per share and (ii) 500,000 shares of the Series C Preferred Stock in an underwritten "follow-on" public offering, at a price of $22.25 per share, and (iii) 335,000 shares of the Series C Preferred Stock in an underwritten "follow-on" public offering at a price of $21.50 per share. We received net proceeds of $17,976 in connection with these post year-end sales.

Capital Expenditures

We use a combination of operating cash flows, borrowings under credit facilities and, from time to time, issuances of debt or common stock to fund significant capital projects. Due to the volatility in oil and natural gas prices, our capital expenditure budgets, both in the short-term and long-term, are adjusted on a frequent basis to reflect changes in forecasted operating cash flows, market trends in drilling and acquisition costs, and production projections.

Total spending on capital projects increased slightly from the same period last year. During the year ended April 30, 2013, we completed Rig 35 and its related winterization. Well related capital spending in Alaska included our Otter exploratory well and drilling and recompletion projects involving our RU-2A, RU-3 and RU-4 wells. Tennessee capital spending related to new drilling projects including our CPP-H-1 and Maynard H-1 wells and a workover of our Brimstone-Bowling #1 well. During the year ended April 30, 2012, capital spending primarily related to construction of and modifications to Rigs 34 and 35.

Liquidity

Cash and Cash Equivalents

As of April 30, 2013, we had $2,551 in cash and cash equivalents.

Debt and Available Credit Facilities

Outstanding debt consisted of $55,307 under our Apollo Credit Facility, $6,000 of which is classified as current debt obligations with the remainder classified as long-term debt on the accompanying consolidated balance sheets as of April 30, 2013. As of April 30, 2013 we had no additional borrowing capacity under our Apollo Credit Facility.

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Contractual Obligations
The following table summarizes our contractual obligations as of April 30, 2013. For additional information regarding these obligations, please see Note 3 - Debt and Note 5 - Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

	Note Reference	Total	2014	2015 - 2016	2017 - 2018	and after
Contractual obligations:[(a)]						
Debt, at face value[(b)]	Note 3	$57,882	$—	$—	$57,882	$—
Interest obligations	Note 3	42,891	10,264	20,528	12,099	—
Dismantlement, removal and restoration (Osprey)[(c)]	Note 5	12,000	1,000	3,500	4,500	3,000
Work commitments[(d)]	Note 5	2,501	625	875	438	563
Rights of way and easements:[(e)]	Note 5					
Osprey to shore pipeline	Note 5	262	13	26	26	197
Osprey to shore optic cable	Note 5	7	—	1	1	5
CIRI Kustatan pipeline easement	Note 5	279	28	56	56	139
West Foreland CIRI/Salamatof agreement	Note 5	184	18	37	39	90
Salamatof surface use agreement	Note 5	450	50	100	100	200
Office and related equipment[(f)]	Note 5	1,063	349	666	48	—
Total contractual obligations		$117,519	$12,347	$25,789		