MILLER ENERGY RESOURCES, INC.
Form 10-K
July 14, 2014

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, 2014
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________________ to __________________________

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
10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock,	New York Stock Exchange

par value $0.0001 per share

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.
o 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.
o 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 o 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 o 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.
o

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	o	Accelerated filer	þ
Non-accelerated filer	o	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o 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, 2013 (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 $189,925,560. As of July 7, 2014, there were 46,076,707 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant's proxy statement relating to registrant's 2014 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, 2014

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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, 2014, 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. Certain capitalized terms not defined immediately below are defined later in this Annual Report on Form 10-K.

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 systems, accounting, controls and reporting performance;
- potential limitations imposed by debt covenants under our senior credit facilities on our growth and our ability to meet our business objectives;
- debt costs under our existing senior credit facilities;
- the ability of our lenders to redetermine the borrowing base under our First Lien RBL;
- our ability to meet the financial and production covenants contained in the First Lien RBL and/or Second Lien Credit Facility;
- whether we are able to complete or commence our drilling projects within our expected time frame or expected budget;
- our ability to recover proved undeveloped reserves;
- 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 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 and natural gas we produce in Alaska;
- 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;
- 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 stock, 10.75% Series C Cumulative Redeemable Preferred Stock (the "Series C Preferred Stock") and 10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock (the "Series D Preferred Stock");
- limitations placed on us with respect to the issuance and/or designation of additional preferred stock;
- litigation risks;
- 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;

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- 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;
- the potential for shortages or increases in costs of equipment, services and qualified personnel;
- 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;
- the potential to incur substantial penalties and fines if we fail to comply with all applicable FERC administered statutes, rules, regulations and orders;
- new regulation on derivative instruments used by us to manage our risk against fluctuating commodity prices;
- the impact that proposed federal, state, or local regulation regarding hydraulic fracturing could have on us;
- the effect that future environmental legislation could have on various costs;
- the impact of certain provisions included in the FY2015 U.S. federal budget on certain tax incentives and deductions we currently use;
- that no dividends may be paid on our common stock for some time;
- cashless exercise provisions of outstanding warrants;
- market overhang related to 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 effects of the change of control conversion features of our Series C and Series D Preferred Stock on a potential change of control;
- the junior ranking of our Series C and Series D Preferred Stock to our Series B Cumulative Redeemable Preferred Stock (the "Series B Preferred Stock") and all of our indebtedness;
- our ability to pay dividends on the Series C or Series D Preferred Stock;
- whether our Series C or Series D Preferred Stock is rated;
- the ability of our Series C or Series D Preferred Stockholders to exercise conversion rights upon a change of control;
- fluctuations in the market price of our Series C or Series D Preferred Stock;
- whether we issue additional shares of Series C or Series D Preferred Stock or additional series of preferred stock that rank on parity with the Series C and Series D Preferred Stock;
- the very limited voting rights held by our Series C and Series D Preferred Stockholders;
- the newness of the Series D Preferred Stock and the limited trading market of the Series C and Series D Preferred Stock; and
- risks related to our continued listing of the Series C and Series D Preferred Stock on the NYSE.

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

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and investor pages. On our website, you can access, free of charge, electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance, and documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. Included in our annual and quarterly reports are the certifications of our principal executive officer and our principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. You may also request printed copies of our committee charters or other governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Our reports filed with the SEC are made available to read and copy at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov. From time to time, we also post announcements, updates, and investor information on our website in addition to copies of all recent press releases. Information on our website or any other website is not incorporated by reference into, and does not constitute 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 Energy Colorado 2014-1, 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, 2014 is referred to as "fiscal 2014" or "2014," 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" and the year ending April 30, 2015 is referred to as "fiscal 2015" or "2015."

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.

MBoe. One thousand barrels of oil equivalent.

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).

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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 or processing of sales-quality crude oil and gas production facilities to market. Used in 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.
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 in 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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(Dollars in thousands, except per share data and per unit data)

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 southcentral Alaska, including the Cook Inlet and Kenai Peninsula, and the Appalachian region of east Tennessee. During fiscal 2015, we expect to expand our operations into Alaska's North Slope (the "North Slope") through our acquisition of Savant Alaska, LLC ("Savant"). Occasionally we offer these services to third-party customers on a contract basis.
During fiscal 2014, 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. In addition to developing the Pacific Energy assets, we also acquired the North Fork Unit and associated assets located on the southern Kenai Peninsula in Alaska during fiscal 2014. These assets include six natural gas wells and related leases (consisting of approximately15,465 net acres), and production and processing equipment, along with twin natural gas transmission pipelines and a multi-year natural gas sales contract held by Anchor Point Energy, LLC, which we are to acquire upon the receipt of necessary regulatory approvals.
Subsequent to the end of fiscal 2014, we entered into an Agreement and Plan of Merger to acquire Savant (the "Merger Agreement"), a company with operations on the North Slope focused on the Badami Unit and its associated assets. Upon the closing of this transaction, Miller will own a 67.5% working interest in the Badami Unit through a subsidiary, along with a 100% working interest in nearby exploration leases, and ownership of midstream assets with a design capacity of 38,500 bopd and 50 miles of pipeline. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. We expect this transaction to close by the end of December 2014, with an effective date of May 1, 2014.
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 increases 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 are focused 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 are 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 employs 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, when available, 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 continues to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

For a more in-depth discussion of our fiscal 2014 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

Proposed Settlement of Class Action Lawsuit

On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs in the purported class action lawsuit styled In re Miller Energy Resources, Inc. Securities Litigation wherein the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, expected to be funded by our director and officer insurance policy. The proposed agreement, when and if it becomes effective, would not be an admission of wrongdoing or acceptance of fault by us or any of the individual defendants named in the complaint. We, along with those individual defendants, have agreed upon the terms of this proposed settlement to eliminate the uncertainties, risk, distraction and expense associated with protracted litigation. The proposed settlement

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remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014. The estimated potential loss and expected insurance recovery are accrued on our consolidated balance sheet as of April 30, 2014.

Intended Disposition of Tennessee Assets

On June 24, 2014, we announced our intent to divest our Tennessee assets in order to allocate our capital to our Alaskan operations and investment opportunities. We have engaged in strategic discussions, but until a definitive agreement is executed, we will continue to conduct our business as usual in Tennessee.

Acquisition of Savant Alaska, LLC

On May 8, 2014, we entered into the Merger Agreement to acquire Savant, subject to due diligence and regulatory approval, for $9,000. We have formed a wholly-owned subsidiary, Miller Energy Colorado 2014-1, LLC ("Miller Colorado"), which will merge with Savant to facilitate the acquisition. Savant currently owns, and, by acquiring Savant, we would indirectly acquire as a result of this merger, a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. In addition to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located in the North Slope with a design capacity of 38,500 bopd, a 500,000 gallon diesel storage tank, 20 megawatts of power generation, a grind and inject solid waste disposal facility and Class 1 disposal well, a one mile airstrip, and two pipelines each running 25 miles in length from Badami to the Endicott Pipeline.

We expect the transaction to close by the end of December 2014, following regulatory approval with a May 1, 2014 effective date.

Entry into First Lien RBL

On June 2, 2014, we entered into a credit agreement (the "First Lien Loan Agreement"), among us, as borrower, KeyBank National Association ("KeyBank"), as administrative agent (in that capacity the “RBL Administrative Agent”), and the lenders from time to time party thereto (the “RBL Lenders”). In addition to KeyBank, the syndicate includes CIT Finance LLC, Mutual of Omaha Bank and OneWest Bank N.A.

The First Lien Loan Agreement provides for a $250,000 senior secured, reserve-based revolving credit facility (the "First Lien RBL"), $60,000 of which was made available to us on the closing date. Amounts outstanding under the First Lien RBL are priced on a sliding scale, based on LIBOR plus 300 to 400 basis points and an undrawn commitment fee, depending upon the level of borrowing (per the table below).

Borrowing Base Utilization Grid

Borrowing base utilization percentage	<25%	≥ 25%, but <50%	≥ 50%, but <75%	≥ 75%, but <90%	≥ 90%, but ≤100%
Spread above LIBOR	3.00%	3.25%	3.50%	3.75%	4.00%
Undrawn commitment fee rate	0.50%	0.50%	0.75%	0.75%	0.75%

The First Lien RBL will mature on the third anniversary of closing. The facility includes leverage, interest coverage, current ratio, minimum gross production, minimum liquidity, asset coverage and change of management control covenants as well as other covenants customary for a transaction of this type. Subject to certain conditions contained in the First Lien Loan Agreement, the First Lien RBL also allows us to implement a discretionary share repurchase plan on terms and conditions reasonably satisfactory to the RBL Administrative Agent and the RBL Lenders. The First Lien RBL contemplates up-front fees, arrangement fees, and ongoing commitment and other fees customary for transactions of this nature.

We drew $20,000 on the closing date under the First Lien RBL, which will be used to provide working capital for development drilling in Alaska. The amounts drawn were subject to an original issue discount equal to 1% of the initial borrowing base. On June 24, 2014, we drew an additional $10,000 under the First Lien RBL.

Also on June 2, 2014, in connection with the First Lien RBL, we, along with all of our consolidated subsidiaries (other than Miller Energy Income 2009-A, LP ("MEI"), Miller Colorado, and Miller Energy Drilling 2009-A, L.P.), entered into a First Lien Guarantee and Collateral Agreement (the “First Lien Guarantee”) with KeyBank, for the benefit of the RBL Lenders from time to time party to the First Lien Loan Agreement. Under the terms of the First Lien Guarantee and related security documents each of our consolidated subsidiaries (other than MEI, Miller Colorado, and Miller Energy Drilling 2009-A, L.P.) have guaranteed

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our obligations under the First Lien RBL and we and those subsidiaries have granted a security interest in substantially all of our assets to secure the performance of the obligations arising under the First Lien RBL.

Amendment of Second Lien Credit Facility Documents

As previously disclosed, in February 2014 we entered into a Credit Agreement with Apollo Investment Corporation ("Apollo") and Highbridge Capital Strategies (the "New Apollo Loan Agreement"), under which a credit facility of up to $175,000 (the "Second Lien Credit Facility") was made available to us. At closing, we drew $175,000 under the Second Lien Credit Facility.

On June 2, 2014, we entered into the Amendment No. 1 to Credit Agreement and Guarantee and Collateral Agreement to the Second Lien Credit Facility and the Second Lien Guarantee (as defined later in this Annual Report). This amendment conforms certain of the covenants, terms and conditions in the Second Lien Credit Facility to match those of the First Lien RBL, including the financial covenants. Under the amendment, the maturity date of the Second Lien Credit Facility was redefined, and will occur on February 3, 2018.

Drilling Activities

On June 7, 2014 we successfully brought online WMRU-2B with an initial seven-day average production rate of approximately 630 boe/d. WMRU-2B is an onshore oil well that was drilled using the Patterson 191 drilling rig. The well was a sidetrack of the unused WMRU-2A wellbore and targeted the Hemlock structure at approximately 14,500 feet. Following completion of WMRU-2B, we moved the Patterson 191 drilling rig to the West Foreland location adjacent to West McArthur River and we are currently drilling the West Foreland #3 well, which is a gas prospect.

On March 31, 2014, we entered into an option to purchase a land-based drilling rig from Baker Process, Inc., which we exercised on May 5, 2014 by entering into a definitive agreement to purchase the rig for $3,250. The 2400 HP rig, which we have named Rig 36, will require approximately $5,000 to $8,000 of improvements and will be used to drill our Sabre prospect.

On the Osprey platform, we are currently drilling RU-9 using Rig 35. The well has a target depth of 18,500 feet in the Hemlock structure, which is south of the Osprey platform. We are currently evaluating our drilling program following completion of the RU-9 well, but tentatively plan to drill the RU-12 grassroots oil well located in the Northern Fault.

Effective July 4, 2014, we entered into an option to purchase the Glacier Drilling Rig, a Mesa 1000 carrier-mounted land-drilling rig primarily for developing the North Fork Field; however, we may use the rig to support other fields. Prior to securing a drilling rig, we attempted to access a previously isolated gas zone in the North Fork 14-25 well which is in the process of being completed.

Subsequent to our fiscal year end we also completed WMRU-8 and are intermittently producing from that well. We are currently evaluating the well as it produces and may follow up with other well work to further increase production rates.

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. We recently acquired the North Fork Unit, located in the southern Kenai Peninsula and Cook Inlet sedimentary basin in Alaska.

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.

	2014 Production	Percentage of Total 2014 Production	2014 Oil and Gas Revenues	4/30/2014 Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves
	(In Boe)			(In MBoe)	
Alaska region [1]	772,993	95%	$66,606	6,111	97%
Appalachian region	43,993	5%	2,863	187	3%
Total	816,986	100%	$69,469	6,298	100%

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1 Cook Inlet production excludes 152,373 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 onshore and offshore fields. As of April 30, 2014, 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

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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 35 miles southwest of Anchorage in Nikiski, which is in 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. Our West McArthur River Unit ("WMRU") and its associated production facility are located on the opposite end of Cook Inlet roughly 14 miles northwest of Nikiski on a small peninsula known as the West Foreland. Also located on the West Foreland is the Kustatan Production Facility which is twelve miles west of Nikiski and four miles south of the West McArthur River Production Facility. The Osprey Platform is located two miles southeast from the tip of the West Foreland and nine miles west of Nikiski. The west side of Cook Inlet is generally accessible, but these assets are isolated from public utilities and infrastructure. Located roughly 60 miles to the northwest of Anchorage is the Susitna Basin, which is perhaps best known for its coal seams in the sedimentary basin underneath the basin and could become a new source of much-needed natural gas. The North Fork field is produced from two well pads located 65 miles south of Nikiski near the community of Nikolaevsk. In contrast to our Alaskan assets located on the west side of the Cook Inlet, these pads are located on the considerably more developed east side as they are on the federal highway system and have access to an electric utility.

Cook Inlet, Susitna Basins, and North Fork Unit

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 under the Cook Inlet. 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.

As of April 30, 2014 and 2013, we owned approximately 340,810 and 100,099 gross (315,913 and 75,202 net) acres of leasehold interests, respectively, along with the exploration license rights to an additional 108,673 and 580,147 gross (108,673 and 580,147 net) acres, respectively, in Alaska. The increase in leased acreage from April 30, 2013 is a result of the conversion of a portion of our expired Susitna #2 License (defined below) to leases, as well as acreage acquired in the North Fork Unit and annual Cook Inlet areawide lease sale. The reduction in licensed acreage from April 30, 2013 is a result of the expiration of the Susitna #2 License (defined below). We also owned interests in twelve crude oil and eleven natural gas wells as of April 30, 2014, compared to ten crude oil and five natural gas wells as of April 30, 2013. The increase in these interests is a result of our drilling activities during fiscal 2014 and the acquisition of the North Fork Unit.

At the time we acquired the Alaskan operations, all of the wells were shut-in, with the exception of one gas well. When we acquired the North Fork Unit, we acquired six natural gas wells, four of which were producing. As of April 30, 2014, seven oil wells and seven gas wells are producing.

Oil wells drilled in this area range from 9,000 feet to 15,500 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 an increased 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. The Cook Inlet Basin contains a thick section of terrestrial tertiary rocks which includes shale, sandstone, and coal.

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 conducted exploration drilling operations between January 2001 and July 2002. 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 six existing shut-in wells. Two of the wells required replacement of the ESPs, and the other four wells required re-

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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, though RU-1 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 wells RU-2A, RU-1A and RU-5B, and completed the reworking of RU-3 and RU-4 as gas wells. Rig 35 has also performed maintenance on RU-D1, our platform disposal well. As we were unable to optimize the performance of RU-1 due to obstructions which were stuck in the lower part of the well bore during the second ESP replacement, we eventually performed a side track on this well bore. We are currently in the process of drilling RU-9, our first grassroots well on the Osprey platform.

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 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 two wells in the field. WF 1 is not currently producing. There is one producing well in the field which has two separately treated zones, WF 2U and WF 2L. 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 this field in which we own a 30% working interest. Production from this field has been intermittent.

Susitna Basin

Included in the Alaskan operations we acquired was a 100% interest in Susitna Basin Exploration License No. 2 ("Susitna #2 License"), 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 Susitna #2 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 Susitna #2 License for a work commitment of $750. The State granted the extension in October 2010. We had the right to convert all or any portion of the licensed acreage into oil and gas leases upon completion of the new work commitment. The Susitna #2 License expired on October 31, 2013. We converted 167,900 acres to 36 leases, at a cost of $504, which represents the payment of the first year's $3.00 per acre annual rental fee.

On April 1, 2011, we were awarded Susitna Basin Exploration License No. 4 ("Susitna #4 License"), 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 $321 toward the fulfillment of its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area. In addition to bonding, we need to spend 50% of the total work commitment amount, or $1,125, by the fourth anniversary of the license, April 1, 2015, or we will forfeit 25% of the license area. If we do not spend at least 25% of the total work commitment amount, or

$563, by April 1, 2015, we will forfeit the entire license.

On April 1, 2012, we were awarded Susitna Basin Exploration License No. 5 ("Susitna #5 License"), 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 $83 toward the fulfillment of its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area. In addition to bonding, we need to spend 50% of the total work commitment amount, or $125, by the fourth anniversary of the license, April 1, 2016, or we will forfeit 25% of the license area. If we do not spend at least 25% of the total work commitment amount, or $63, by April 1, 2016, we will forfeit the entire license.

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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 the Redoubt Unit and West McArthur River Unit. 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 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 quarterly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,
- 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 Unit 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. We believe CIE has adequately fulfilled these commitments.

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

On March 11, 2011, CIE entered into a Performance Bond Agreement under its AOA with the State of Alaska. Under the Performance Bond Agreement, CIE 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 funds held by the state in an escrow account will be credited towards the $18,000.

Failure to submit the information required by the AOA 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.

North Fork Properties

On November 22, 2013, CIE entered into a purchase and sale agreement by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC (together, the "North Fork Sellers") and CIE (the "North Fork Purchase Agreement"). In this transaction, CIE (i) acquired a 100% working interest in six natural gas wells and related leases (consisting of approximately 15,465 net acres) referred to as the "North Fork Unit" in the Cook Inlet region of the State of Alaska, together with other associated rights, interests and assets for $59,975, subject to certain adjustments and (ii) subject to regulatory approval, has the right to acquire all the issued and outstanding membership interests of Anchor Point Energy, LLC (the "Anchor Point Equity"), a limited liability company owning certain pipeline facilities and related assets which service the North Fork properties, for 213,586 shares (valued at approximately $5,000) of the Company's Series D Preferred Stock. Collectively, we refer to the assets as the "North Fork Properties."

The acquisition of the North Fork Properties closed on February 4, 2014 and the proposed acquisition of the Anchor Point Equity will close upon receiving approval from the Regulatory Commission of Alaska, subject to customary closing conditions. Upon the closing of the acquisition, the portion of consideration consisting of Series D Preferred Stock and an assignment of Anchor Point Equity were deposited into an escrow account. These will be disbursed upon the closure of the Anchor Point Equity acquisition pursuant to the terms of the North Fork Purchase Agreement.

The North Fork Unit and gas field is located on the southern Kenai Peninsula, east of the community of Anchor Point. Production at the time of acquisition was approximately 7.0 MMcfd (1,167 boe/d). Current production is approximately 9.9 MMcfd (1,706 boe/d), and is expected to increase as CIE performs well optimizations and commences full field development of up to 24 additional wells. Anchor Point Energy, LLC ("Anchor Point") owns and operates nine miles of twin 4-inch natural gas transmission pipelines and is party to a multi-year natural gas sales contract with an affiliate of ENSTAR for use by ENSTAR (the "ENSTAR Gas Sales Agreement"), the largest natural gas utility in Alaska. There is approximately 2.9 BCF remaining of a 10.0 BCF commitment to ENSTAR at a price of approximately $7.00 per Mcf. Our acquisition of Anchor Point and the Anchor Point Equity is currently pending and awaiting regulatory approval; however, under the terms of the acquisition agreement with the North Fork Sellers, the acquisition will be effective as of May 1, 2014. Currently, under a separate agreement between CIE and

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Anchor Point mirroring the ENSTAR Gas Sales Agreement ("APE Gas Sales Agreement"), CIE is selling natural gas from the North Fork Unit to Anchor Point (for sale by Anchor Point to ENSTAR). The price paid to CIE by Anchor Point for that natural gas is equal to the amount paid to Anchor Point for such gas (by the third party acquiring it), minus a tariff amount established by the Regulatory Commission of Alaska for transportation on the North Fork Pipeline which is currently equal to $1.95 per Mcf. In addition, CIE is also selling and delivering natural gas from the North Fork Unit to other purchasers.

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 through 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 own and operate a total of 379 gross (261 net) oil and gas wells in which we own an interest in the State of Tennessee. As of April 30, 2014, we owned approximately 46,864 gross (37,999 net) acres of leasehold interests with 200 gross (144 net) producing oil wells and 179 gross (117 net) producing gas wells in which we own an interest. This is a decline of 3,396 gross (1,878 net) acres from April 30, 2013. The decline in gross and net acreage is attributable to undeveloped acreage leases being allowed to lapse. 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 2014, Miller focused its operations on continuing to improve our horizontal drilling results and on the acquisition of additional working interests in wells in which we already have a working interest. These working interest acquisitions increase our net production.

In October 2013, we drilled and completed our third horizontal oil well in the Fort Payne Limestone in Tennessee, the Brimstone et. al H-1, which is located in the Low Gap Field. We are producing this well and have begun a reservoir study to present to the State to unitize the Low Gap Field in order to allow maximum oil recovery, conserve associated gas, and pave the way for a gas pressure maintenance program that will further enhance production.

In addition to the horizontal well program, we continued to acquire working interest in wells we operate and also purchased ten wells and associated infrastructure in March of 2014. We also received the permits needed from the State of Tennessee to begin construction of a portable gas processing plant in the Burrville area, enabling us to recover and sell liquids from high BTU gas from our gas wells and other operators' wells in the area and sell the required lower BTU gas to the local utility.

Principal Markets and Customers

The existing markets for natural gas production in southcentral Alaska are the Tesoro Nikiski Refinery, utility companies such as ENSTAR, 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

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Refinery. Crude oil is shipped by pipeline and tanker vessel to the Tesoro Nikiski Refinery, operated by Tesoro Alaska Petroleum Company.
Under the terms of the Alaska crude oil sales contract, Tesoro Refining and Marketing Company ("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 and 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 Tesoro's Alaska Refinery. In fiscal 2014, 2013 and 2012, purchases by Tesoro accounted for 93%, 100%, and 100%, 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. Gas production in excess of our internal needs is sold to third parties.
In addition, as described above, CIE currently sells gas to Anchor Point under the APE Gas Sales Agreement. Anchor Point is further obligated to make sales to ENSTAR’s affiliate under the ENSTAR Gas Sales Agreement. Under this arrangement, CIE receives a price for its natural gas sold to Anchor Point equal to the price paid to Anchor Point under the ENSTAR Gas Sales Agreement of approximately $7.00 per Mcf minus a tariff amount established by the Regulatory Commission of Alaska of $1.95 per Mcf.
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 Swan Creek Partners, LLC, formerly Tengasco, Inc. 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 2014, 2013 and 2012, sales to Barrett Oil Purchasing and Sunoco, collectively, represented approximately 70%, 81%, and 35%, 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 fiscal 2014, we have used Rig 35 to restore or commence production from oil wells RU-1, RU-7, RU-1A, RU-2A and RU-5B and gas wells RU-3 and RU-4. Rig 35 has also performed maintenance on our platform disposal well, RU-D1, and is drilling our first Redoubt grassroots well, RU-9.
During fiscal 2014, we leased the Patterson-191 rig in order to drill our first well in the Sword prospect. Sword #1 came online on November 18, 2013 with an initial gross production rate of 883 boe/d from one of three productive

zones. Since bringing the well online, we have tested the two other productive zones and received two permits to commingle production from the different zones. In addition to the Sword #1 well, the Patterson-191 rig has also drilled the WMRU-8 and WMRU-2B oil wells, and is currently drilling the WF-3 gas well.

On March 31, 2014, we entered into an option to purchase a land-based drilling rig from Baker Process, Inc. for $1,500, which we exercised on May 6, 2014 by making additional payments of $1,750 and entering into a definitive agreement to purchase the rig for a total of $3,250. The 2400 HP rig, which we have named Rig 36, will require approximately $5,000 to $8,000 of improvements in order to drill our Sabre prospect.

While we have plans to drill up to 24 additional wells in our newly-acquired North Fork Unit, because this acquisition occurred in the fourth quarter of fiscal 2014, we did not commence any drilling in this field during this fiscal year.

In Tennessee, we drilled one producing development well, Brimstone et. al H-1, during fiscal 2014.

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In fiscal 2013, we incurred dry hole costs on one well in Tennessee, and we drilled two new development wells; one well that is producing and one well that is classified non-producing.
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					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Producing						
Cook Inlet	3	3	—	—	—	—
Appalachian region	1	1	1	1	—	—
Total producing	4	4	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	4	4	2	2	2	2
Exploratory:						
Productive						
Cook Inlet	1	1	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total productive	1	1	—	—	—	—
Dry						
Cook Inlet	—	—	—	—	1	1
Appalachian region	—	—	1	1	—	—
Total dry	—	—	1	1	1	1
Pending determination	—	—	—	—	—	—
Total exploratory	1	1	1	1	1	1
Total drilling activity	5	5	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, 2014 is set forth below:

	Producing Wells					
	Gross [(a)]			Net [(b)]		
	Oil	Gas	Total	Oil	Gas	Total
Cook Inlet	11	12	23	7	7	14
Appalachian region	200	179	379	144	117	261
Total	211	191	402	151	124	275

(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,		
	2014	2013	2012
Net production - boe[1]	816,986	317,606	371,843
Average oil price - per bbl	$100.85	$101.53	$93.10
Average natural gas price - per mcf	$6.26	$3.52	$3.47
Average lease operating expenses - per boe[2]	$24.71	$70.17	$30.40

1 Net production for fiscal 2014, 2013 and 2012 excludes 152,373, 57,123 and 33,956 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.

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The following table describes, for each of the last three fiscal years, net oil and gas production volumes, average sales price per bbl, and average production cost per boe after deducting royalties and interests of others, with respect to oil and gas production attributable to our interest in the West McArthur River, North Fork and Redoubt Shoals fields, which comprise at least 15% of our total proved reserves.

	For the Year Ended April 30,		
	2014	2013	2012
Net production - boe			
West McArthur River[1]	245,718	200,123	234,301
Redoubt Shoal[2]	413,471	75,535	91,455
North Fork	98,725	—	—
Average oil price - per bbl			
West McArthur River	$102.84	$103.74	$95.33
Redoubt Shoal	$101.50	$100.03	$89.98
Average natural gas price - per mcf			
Redoubt Shoal	$7.02	$—	$—
North Fork	$6.96	$—	$—
Average lease operating expenses - per boe			
West McArthur River	$31.23	$28.76	$18.08
Redoubt Shoal[3]	$21.16	$190.16	$57.30
Average lease operating expenses - per mcf			
North Fork	$0.24	$—	$—

1 Net production for West McArthur River for fiscal 2014, 2013 and 2012 excludes 15,198, 11,350 and 12,669 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 Net production for Redoubt Shoal for fiscal 2014, 2013 and 2012 excludes 123,423, 25,301 and 3,796 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

3 Fiscal 2013 average lease operating expenses per boe for Redoubt Shoal 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, 2014:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Cook Inlet	25,596	25,164	408,935	399,420	434,531	424,584
Appalachian region	11,160	7,560	35,704	30,439	46,864	37,999
Total acreage	36,756	32,724	444,639	429,859	481,395	462,583

During fiscal 2014, 477,521 gross (477,521 net) undeveloped acres expired in Alaska. A significant portion of this acreage was encompassed by our Susitna #2 License, which consisted of 471,474 acres and expired in accordance with its terms as of October 31, 2013. We were able to convert 167,900 acres from this license to 36 leases, which now represents 41% of our gross (42% net) total undeveloped acreage as of April 30, 2014. During fiscal 2014, 2,148 gross (1,678 net) undeveloped acres expired in Tennessee.

The substantial majority of our undeveloped acreage is located in the State of Alaska. As of April 30, 2014, we had 15,132 gross (15,132 net) undeveloped acres set to expire in Alaska by April 30, 2015 if production is not established or we take no other action to extend the terms of the applicable leases. The remainder of our Alaskan undeveloped acreage is not scheduled to expire until at least April 30, 2018, with the notable exception of our Susitna #5 License consisting of 45,764 gross (and net) acres which is scheduled to expire prior to April 30, 2017. Should we fulfill the terms of the Susitna #5 License, we will be able to convert all or any portion of the license into oil and gas leases. No material amount of acreage is scheduled to expire in Tennessee by April 30, 2015. We strive to extend the terms of many of these leases and licenses through operational or administrative actions, but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third parties including governments.

As of April 30, 2014, 8% of our gross (6% net) Alaskan undeveloped acreage was held by production, and 100% of our gross (100% net) Tennessee undeveloped acreage was held by production.

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.

"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.

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The following table shows proved oil and gas reserves as of April 30, 2014, based on average commodity prices in effect on the first day of each month in fiscal 2014, 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, 2014			
Reserves category:	Oil (MBbls)	Natural Gas (MMcf)	MBoe	Reserve %
PROVED				
Developed				
Cook Inlet	4,129	11,891	6,111	57%
Appalachian region	135	311	187	2
Undeveloped				
Cook Inlet	1,832	15,439	4,405	41
Appalachian region	—	—	—	—
Total proved	6,096	27,641	10,703	100%

Our estimates of proved reserves, proved developed reserves and proved undeveloped ("PUD") reserves as of April 30, 2014, 2013 and 2012, 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.
The following table details the changes in MBoe of our PUD reserves.

	MBoe	
PUD as of April 30, 2013	6,828	
Conversion to proved developed reserves	(1,880	)
Acquisition of reserves in place	2,212	
Extensions, discoveries and other additions	948	
Revisions of previous estimates	(3,703	)
Sales of minerals in place	—	
PUD as of April 30, 2014	4,405	

During fiscal 2014, we converted 1,880 MBoe of PUD reserves to proved developed reserves by drilling the RU-2A, RU-5B, and WMRU-8 wells. As part of our capital budget , among other wells planned for fiscal 2015, we expect to drill RU-3, RU-4, and WF-3, converting them from PUD reserves to proved developed reserves. Further, we believe that we will develop our PUD reserves and convert them to proved developed reserves within five years from the time each well was initially booked as a PUD.
Also during fiscal 2014, we acquired 2,212 MBoe in the North Fork Properties acquisition which closed in February 2014. As a result of ongoing drilling and completion activities during fiscal 2014, we reported extensions, discoveries, and other additions of 948 MBoe which are attributable to the offsetting PUD location from bringing the Sword #1 well online within the West McArthur River area. The downward revisions were primarily driven by a decrease in PUD volumes. During the fiscal 2014 year we made a change in our independent reserve engineer from Ralph E. Davis Associates, Inc. to Ryder Scott Company, L.P. for our Alaska properties. The decrease in PUD volumes resulted primarily from changes in the professional judgment of our independent petroleum engineer, additional production history leading to lower projected recovery estimates and to a lesser extent, changes in price and cost.

Preparation of Oil and Gas Reserve Information

Our reserve estimates for oil and natural gas as of April 30, 2014 for our Cook Inlet and Appalachian region assets were prepared by Ryder Scott Company, L.P. and Ralph E. Davis Associates, Inc., respectively, both of which are independent engineering firms. The report prepared by Ryder Scott Company, L.P. covered 98% of our reserves and the report prepared by Ralph E. Davis,

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Inc. covered 2% of our reserves. Our reserve reports, which are filed as exhibits to this annual report, were prepared using engineering and geological methods widely accepted in the industry. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petro physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. 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.
Our reserve estimates for oil and natural gas as of April 30, 2013 and 2012 for our Cook Inlet and Appalachian region assets were prepared by Ralph E. Davis Associates, Inc.

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. Mr. David M. Hall, our Chief Operating Officer (and Chief Executive Officer of CIE), is the technical person primarily responsible for overseeing the preparation of our proved reserve estimates by independent petroleum engineers. Mr. Hall has over 20 years of experience in oil and gas operations, development and reservoir engineering, including over 20 years of experience with many of our Alaska oil and gas assets, as a result of former positions held with our predecessors in title, Forest Oil and Pacific Energy. Mr. Hall's experience includes: (i) managing our geological, geophysical, production, and drilling groups, including setting directives for these groups; (ii) estimating reserves and forecasting for property evaluations and development planning; (iii) predicting reserves and performance for well proposals; (iv) supervising and working with third party reserve engineering firms; (v) developing and applying reservoir optimization techniques; (vi) overseeing the development of reservoir monitoring and surveillance programs, and overseeing performance of reservoir characterization studies; and (vii) coordinating geological and petrophysical studies.
We provide the engineering firms with estimate preparation materials such as property interests, production, current operation costs, current production prices and other information. This information is reviewed by the Chief Operating 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.

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. During 2014 and 2013, other revenues totaled $1,089, or 2%, and $4,886, or 14%, respectively, of our consolidated total revenues. The decrease in other revenues primarily resulted from the completion of the road and pad building project in the Cook Inlet region which contributed 51% of our other revenue in 2013.

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, as well as both oil and gas sales contracts in place. 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., Champ Oil, ENREMA, LLC, and Swan Creek Partners, LLC, formerly 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.

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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 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, future gas production is assumed to be sold at contract terms similar to both our existing contract prices and 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 $1,909 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. 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. As of April 30, 2014, we have funded $1,000 of this amount. An existing interest bearing account containing approximately $7,026 as of April 30, 2014 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. We do not anticipate any additional bonding requirements for the North Fork Unit.
CIE has a work commitment bond for Otter in the amount of $1,200. In order to satisfy the work commitment, the Otter well has to be finished to a depth sufficient to test the Beluga formation by March 31, 2016. Additionally, we

have a work commitment bond for Olson Creek in the amount of $250. We must commence drilling by September 1, 2014 in order to satisfy the work commitment under this bond.

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

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bonds cost $2 per well. The cost for the plugging bonds range from $2 to $3 per well depending on depth or $20 for ten 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" 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 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 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 the corporation. These 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.

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, 2014, we had 84 employees.

Offices

Our principal executive offices are located at 9721 Cogdill Road, Suite 302, Knoxville, Tennessee. At April 30, 2014, we maintained regional exploration and/or production offices in Huntsville and Sunbright, Tennessee and Anchorage, Alaska, and had entered into a lease establishing our Houston, Texas administrative office with a commencement date of May 15, 2014. We lease 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.

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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 resulted in litigation which was settled during fiscal 2014 for $1,250.

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 completed five acquisitions, including the North Fork Unit assets, and are in the process of completing a merger to acquire Savant.

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 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 owned 1% of MEI, however due to the shared management of our company and MEI, we have consolidated this entity.

On February 3, 2014, we repaid all obligations under and terminated the First Secured Promissory Note dated as of November 1, 2009, a Second Secured Promissory Note dated as of December 15, 2009, a Third Secured Promissory Note dated as of May 15, 2010, and a Loan and Security Agreement dated as of March 19, 2010 (as amended, supplemented or otherwise modified prior to the date hereof, the "MEI Loan Documents"). Once paid, in accordance with the governing documents of MEI, the interests of the limited partners in MEI were effectively redeemed and ceased to exist. As a result, under Delaware law, MEI ceased to be a "limited partnership" when no new limited partners were admitted within the statutorily prescribed time limit. As the Company was the sole general partner and sole remaining holder of any equity interest in MEI, MEI has therefore been legally consolidated into the Company. We are in the process of preparing a certificate of cancellation for filing with the State of Delaware with respect to MEI.

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 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 #2 License as well as completed 3D seismic geology and other production facilities. At 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. 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.

On February 4, 2014, we acquired the North Fork Unit and its associated assets. As part of that transaction, subject to the receipt of regulatory approval, we will also acquire 100% of the membership interests in Anchor Point. We paid a total of approximately $64,557, after customary adjustments, in a combination of $59,557 and 213,586 shares (valued at approximately $5,000) of our Series D Preferred Stock for these assets, including the Anchor Point Equity. The assets acquired included six natural gas wells, approximately15,465 net acres, and production and processing equipment. Anchor Point is the owner and operator of nine miles of twin 4-inch natural gas transmission pipelines and a party to the ENSTAR Gas Sales Agreement.

ITEM 1A. RISK FACTORS.

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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 years 2014, 2013 and 2012. 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 $10,693 in fiscal 2014, $32,349 in fiscal 2013 and $25,085 in fiscal 2012. As a result of the continued expansion of our business during fiscal 2014, 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 Alaska, and as we continue to make acquisitions. 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 and raise capital 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 do not see 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 2014, 2013, and 2012, we and our independent public accounting firm 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 2014, 2013, and 2012 we and our independent registered public accounting firm identified a number of deficiencies in our internal control over financial reporting, including a “material weakness” as defined in the standards established by the Public Company Accounting Oversight Board Standard (United States). 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 2014, 2013 and 2012 related to an insufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. 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 2015 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. Further, we 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.
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 First Lien RBL and Second Lien Credit Facility contain a number of significant covenants that, among other things, restrict our ability to:
- pay for general and administrative expenses;

- make capital expenditures on new wells without lender consent;
- 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 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;

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- 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.

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 First Lien RBL or Second Lien Credit Facility.

We are subject to substantial debt costs under the terms of our Second Lien Credit Facility with Apollo Investment Corporation and Highbridge Capital Strategies. Monies borrowed are subject to an interest rate of LIBOR + 9.75% per annum, with a 2.00% LIBOR floor.

As described above in this Annual Report, in February 2014 we entered into the New Apollo Loan Agreement with Apollo and Highbridge Capital Strategies, under which the Second Lien Credit Facility was made available to us. Our total indebtedness under our Second Lien Credit Facility is $175,000. That amount bears interest at a rate of LIBOR plus 9.75% (subject to a 2.00% LIBOR floor) and are subject to a make whole premium and repayment premiums payable on certain repayments of the loans. These debt costs may be substantial, and will adversely impact our results until the facility has been repaid.

We are subject to redeterminations of the Borrowing Base under our First Lien RBL. If our reserves decrease, or if other events occur which cause our lenders to decrease the Borrowing Base to an amount lower than our current outstanding borrowings, any excess borrowings would become immediately due and payable.

Our First Lien RBL provides for redeterminations of our Borrowing Base on both a regularly scheduled basis and an interim basis. Our lenders rely on certain engineering reports, including reserve reports, as well as our swaps and hedges to determine our Borrowing Base. Should we experience a decline in our reserves, sell a certain amount of our oil and gas properties, cancel a certain amount of our hedges or swaps, or experience other events which negatively impact the status of our oil and gas properties with respect to our lenders' normal oil and gas lending criteria, our lenders may determine to lower our Borrowing Base. Should we have an outstanding balance in excess of a lower redetermined Borrowing Base, the amount in excess of the new Borrowing Base would become immediately due and payable, and we would need to come up with sufficient cash to repay such amounts. This could require us to raise additional capital at an inopportune time, or on terms not favorable to us.

Our inability to timely repay the amount in excess of the new Borrowing Base could result in a default under the First Lien RBL and our Second Lien Credit Facility. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our First Lien Loan Agreement and New Apollo Loan Agreement. The accelerated debt would become 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.

If we fail to meet financial and production covenants contained in the First Lien RBL and Second Lien Credit Facility, we may be limited in our ability to make additional borrowings, 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, Series C, or Series D Preferred Stock. If the failure to meet these covenants results in a default, we could face the acceleration of our indebtedness under the First Lien RBL or Second Lien Credit Facility which would become immediately due and payable.

Both our First Lien RBL and Second Lien Credit Facility require 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 First Lien RBL or Second Lien Credit Facility could eventually result in our failing to meet one or more of the financial and production-level covenants, 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 First Lien RBL or Second Lien Credit Facility. A default under either facility, if not cured or waived, could result in acceleration of all indebtedness outstanding under both facilities. The accelerated debt would become 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.

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Material differences between the estimated and actual timing of critical events may affect the completion and commencement of production from our projects. In addition, unexpected problems or delays in our drilling operations may cause us to spend additional amounts over those budgeted for 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 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 including problems with drilling. Delays and differences between estimated and actual timing of critical events may adversely affect our production and our projected cash flows from operations, and could cause us to spend additional amounts over those budgeted for our projects which could be substantial.
The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Approximately 41% of our total estimated proved reserves at April 30, 2014 were proved undeveloped 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 we 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 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.

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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.

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, all of which could result in our making decisions to delay drilling on certain leases notwithstanding the resulting expiration of those leases that could occur.

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.

Approximately 108,673 acres of our total acreage consists of the two Susitna Basin Exploration Licenses in Cook Inlet, Alaska. These two licenses require us to spend a total of $2,500 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 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 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 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.

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

Anchor Point has entered into the ENSTAR Gas Sales Agreement with ENSTAR's affiliate under which a majority of our natural gas produced in Alaska is ultimately sold to ENSTAR. We generally do not require letters of credit or collateral to support these trade receivables. Accordingly, a material adverse change in the financial condition if ENSTAR and its affiliates could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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.

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.

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.

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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 our publicly traded securities, including our common stock, Series C Preferred Stock, and Series D 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 crises in Europe (related primarily to concerns that certain European countries may be unable to pay their national debt) had similar, although less pronounced, effects. 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 and Series D Preferred Stock, the return we receive on our investments, as well as other unknown adverse effects on us or the economy in general.

Covenants preventing the issuance and/or designation of additional preferred stock may limit our ability to raise funds on advantageous terms or through additional preferred stock offerings.

Our First Lien RBL contains certain negative covenants that may prohibit us from issuing more than approximately $15,000 in shares of Series B, Series C, or Series D Preferred Stock after the closing of the First Lien RBL. The First Lien Loan Agreement also prohibits us from designating new classes of preferred stock with terms that are more onerous to us than those contained in either the Series C or Series D Preferred Stock designations. These limitations could result in a loss of flexibility in our ability to raise funds quickly through our at-the-market agreements, or should we reach the $15,000 additional limit, at all.

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 may not contain any reserves, or the reserves contained in our consolidated financial statements may be insufficient, 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.

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 First Lien RBL and our Second Lien Credit Facility.
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.

Shortages or increases in costs of equipment, services, and qualified personnel could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect our ability to execute our exploration and development plans as projected.

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;

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- 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 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 Dodd-Frank 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.

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.

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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." 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 2015 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 March 4, 2014, the President unveiled his $3.9 trillion U.S. federal budget proposals for fiscal year 2015. 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 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 no budget has been passed at this time, 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 First Lien RBL and Second Lien Credit Facility do 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, 2014, we have common stock warrants outstanding to purchase an aggregate of 1,109,150 shares of our common stock with an average exercise price of $4.98 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.
We have outstanding options and warrants, if exercised, would increase our currently outstanding common stock by approximately 32%. The exercise of these options and 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 100,000,000 shares of preferred stock with such designations, preferences and rights as determined by our Board of Directors. At July 7, 2014 we had 46,076,707 shares of common stock outstanding together with outstanding options and warrants to purchase an aggregate of 14,811,847 shares of common stock at exercise prices of between

$0.01 and $6.95 per share. Future sales of common stock under effective registration statements, 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 shares of our outstanding common stock will increase by approximately 14,811,847, 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, 2014, we have a derivative liability of $7,207. We recognized a non-cash loss on derivatives of $6,365 in fiscal 2014, a non-cash gain of $5,235 in fiscal 2013, and a non-cash loss of $3,436 in fiscal 2012. The amount of quarterly non-cash gains or losses we will record in future periods is

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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.

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, 2014, 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 features of our Series C and Series D Preferred Stock may prevent a change in control, or discourage a third party from acquiring us.

The Change of Control conversion features of the Series C and Series D 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, Series C, and Series D 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 and Series D Preferred Stock

The Series C and Series D Preferred Stock rank junior to our Series B Preferred Stock and to all of our indebtedness and other liabilities and are 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 and Series D Preferred Stock only after all of our indebtedness and other liabilities have been paid. The rights of holders of the Series C and Series D 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 and/or Series D 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 and Series D Preferred Stock effectively rank 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 and Series D 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 or Series D 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 and Series D Preferred Stock. At April 30, 2014, we had $184,202 of indebtedness, on a consolidated basis (including obligations arising under our Series B Preferred Stock), ranking senior to the Series C and Series D Preferred Stock. Our First Lien RBL and Second Lien Credit Facility prohibits payments of dividends on the Series C and Series D 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 and Series D Preferred Stock.

Future offerings of debt or senior equity securities may adversely affect the market price of the Series C or Series D 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 or Series D Preferred Stock and may result in dilution to owners of the Series C and Series D 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 and Series D Preferred Stock will bear the risk of our future offerings, reducing the market price of the Series C and Series D Preferred Stock and diluting the value of their holdings in us.

We may not be able to pay dividends in cash on the Series C or Series D 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 and Series D Preferred Stock will require us to have

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

The Series C and Series D Preferred Stock have not been rated.

We have not sought to obtain a rating for the Series C or Series D 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 or Series D Preferred Stock. In addition, we may elect in the future to obtain a rating for the Series C or Series D Preferred Stock, which could adversely affect the market price of the Series C or Series D 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 or Series D Preferred Stock.

Series C or Series D 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 or Series D 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 or Series D Preferred Stock held by such holder, in which case such holder will have the right only with respect to shares of Series C or Series D Preferred Stock that are not called for redemption) to convert some or all of such holder's Series C or Series D 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 or Series D Preferred Stock prior to November 1, 2017 (and we are subject to a general prohibition on redemptions under the terms of our First Lien RBL and Second Lien Credit Facility prior to the date which is 30 days after all of our obligations and the lender commitments under those credit facilities have been satisfied), we have a special optional redemption right to redeem the Series C or Series D Preferred Stock in the event of a Change of Control, and holders of the Series C or Series D 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 or are prohibited from redeeming the Series C or Series D Preferred Stock prior to the Change of Control Conversion Date, then, upon an exercise of the applicable conversion rights, the number of shares of our common stock or other applicable consideration that the holders of Series C or Series D Preferred Stock will be entitled to receive will be limited to a maximum of 9.51 multiplied by the number of shares of Series C Preferred Stock to be converted and 7.1225 multiplied by the number of Series D Preferred Stock to be converted, respectively.

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

The market price of the Series C or Series D 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 or Series D Preferred Stock;
- trading prices of common and preferred equity securities issued by other energy companies;
- the annual yield from distributions on the Series C or Series D 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.

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

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

We are allowed to issue additional shares of Series C or Series D Preferred Stock and additional series of preferred stock that would rank equally to the Series C and Series D 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 and Series D Preferred Stock without any vote of the holders of the Series C or Series D Preferred Stock. The issuance of additional shares of Series C or Series D Preferred Stock and preferred stock that would rank on parity with the Series C and Series D Preferred Stock could have the effect of reducing the amounts available to the current holders of our Series C and Series D 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 and Series D Preferred Stock if we do not have sufficient funds to pay dividends on all Series C and Series D Preferred Stock outstanding and other classes of stock with equal priority with respect to dividends.

In addition, although holders of Series C and Series D Preferred Stock are entitled to limited voting rights with respect to such matters, the Series C and Series D 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 and Series D Preferred Stock. As a result, the voting rights of holders of Series C and Series D 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 and Series D Preferred Stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series C or Series D 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 and Series D Preferred Stock have extremely limited voting rights.

Voting rights as a holder of Series C or Series D 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 and Series D 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 and Series D Preferred Stock, two additional directors to our board of directors, subject to certain limitations, in the event that a “Listing Event” (defined below) occurs or four quarterly dividends (whether or not consecutive) payable on the Series C or Series D Preferred Stock are in arrears (as applicable), and with respect to voting on amendments to our amended and restated charter, as amended, or articles of amendment relating to the Series C or Series D Preferred Stock that materially and adversely affect the rights of the holders of Series C or Series D Preferred Stock or authorize, increase or create additional classes or series of our shares that are senior to the Series C and Series D Preferred Stock. A “Listing Event” means, with respect to the Series C or Series D Preferred Stock, respectively, if that class of stock is not listed on certain specified national stock exchanges (including the New York Stock Exchange or NASDAQ) for 180 or more consecutive days. Other than the limited circumstances described in this Annual Report, holders of Series C and Series D Preferred Stock do not have any voting rights.

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

The Series D Preferred Stock is a relatively new issue of securities with only a limited trading market. The volume of trades of shares of both the Series C and Series D Preferred Stock on the New York Stock Exchange ("NYSE") is often low, and an active trading market on the NYSE for the Series C and Series D Preferred Stock may not be maintained in the future and may not provide adequate liquidity. The liquidity of any market for the Series C and Series D 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 and Series D Preferred Stock, the market for similar securities and the interest of securities dealers in making a market in the Series C and Series D Preferred Stock. As a result, the ability to transfer or sell the Series C and Series D Preferred Stock could be adversely affected.

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

Other than in connection with a Change of Control, the Series C and Series D Preferred Stock do not contain provisions that are intended to protect stockholders if our common stock is delisted from the NYSE. Since the Series C and Series D Preferred Stock have no stated maturity date, stockholders may be forced to hold their shares of the Series C or Series D Preferred Stock

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and receive stated dividends on the Series C or Series D 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 and Series D Preferred Stock will be delisted from the NYSE as well. Accordingly, if the Series C or Series D Preferred Stock or our common stock is delisted from the NYSE, the ability to transfer or sell shares of the Series C or Series D Preferred Stock may be limited and the market value of the Series C or Series D Preferred Stock will likely be materially adversely affected.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 3. LEGAL PROCEEDINGS.

On May 11, 2011, the Court of Appeals of Tennessee at Knoxville returned its opinion in the case styled CNX Gas Company, LLC v. Miller Petroleum, Inc., et al. As previously reported, CNX Gas Company, LLC ("CNX") commenced litigation on June 11, 2008 in the Chancery Court of Campbell County, State of Tennessee to enjoin us from assigning or conveying certain leases described in the Letter of Intent signed by CNX and our Company on May 30, 2008, to compel us to specifically perform the assignments as described in the Letter of Intent, and for damages. After the trial court granted the motion for summary judgment of the Company and other party defendants and dismissed the case, finding that there were no genuine issues of material fact and that we were entitled to judgment as a matter of law, CNX appealed. All parties filed briefs and the Court of Appeals heard oral arguments on May 18, 2010. In its May 11, 2011 opinion, the Court of Appeals reversed the trial court's grant of summary judgment in favor of our Company and the other party defendants, and remanded the case back to the trial court for further proceedings. On July 28, 2011, the case was dismissed without prejudice on the motion of CNX.

This action was revived on August 4, 2011, when a breach of contract case was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled CNX Gas Company, LLC v. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC and Scott Boruff, arose from the same allegations as the previous action in the state court. The federal case sought money damages from us for breach of contract; however, unlike the previous action, it did not seek specific performance of the assignments at issue. The Plaintiff claimed that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We reached a settlement with the Plaintiff on January 24, 2014, wherein we would pay the Plaintiff $1,250 in exchange for their agreement to dismiss the case with prejudice. The Company recorded a loss of $1,250 in other operating (income) expense, net in its consolidated statement of operations for the year ended April 30, 2014 in connection with this settlement.

On May 17, 2011, we were served with a lawsuit filed in the United States District Court for the Eastern District of Tennessee at Knoxville by Troy D. Stafford, the former Chief Financial Officer of CIE. The suit, styled Troy D. Stafford v. Miller Petroleum, Inc., Civil Action No. 3-11CV-206, claims that we terminated Mr. Stafford's employment without cause in contravention of the terms of the Purchase and Sale Agreement between us and the sellers of CIE ("PSA"), failed or refused to pay his salary, severance, percentage of purchase price, expenses or stock warrants and violated a duty of good faith and fair dealing. The suit sought damages in excess of $3,000, which includes $2,687 of damages for loss of vested warrants. We believe that all of the asserted claims were baseless, particularly in view of the fact that we issued the warrants in accordance with the terms of the PSA. We believe that we had appropriate cause to dismiss Mr. Stafford's employment after discovering that he had breached certain representations and warranties in the PSA, and had acted in violation of our Code of Conduct. We filed our Answer and conducted discovery. On January 21, 2013, Mr. Stafford's attorney filed a motion to withdraw as counsel, and on April 2, 2013, Mr. Stafford filed a motion to proceed pro se. On February 24, 2014, we filed a Motion to Dismiss with Prejudice based on Plaintiff’s failure to prosecute his case since April 2, 2013, Plaintiff’s having missed filing deadlines, and his having failed to appear to give his deposition both times we have noticed it. On February 26, 2014, the Court entered an Order to Show Cause, requiring the plaintiff to demonstrate why his case should not be dismissed. On March 14, 2014, the plaintiff filed a Motion for Voluntary Dismissal, Without Prejudice through his new attorney. On June 3, 2014, the court granted plaintiff’s motion to dismiss without prejudice, but did so with the condition that plaintiff must reimburse us for costs incurred by us as a result of his failure to cooperate in discovery in this case in the amount of $9 prior to his being allowed to refile the case. As such, this case has been dismissed and there is no further action currently required.

On June 15, 2011, a breach of contract lawsuit was filed against us and CIE in the United States District Court for the Eastern District of Pennsylvania styled VAI, Inc. v. Miller Energy Resources, Inc., f/k/a Miller Petroleum, Inc. and Cook Inlet Energy, LLC. The Plaintiff alleges three causes of action: (1) breach of contract, (2) unjust enrichment, and (3) breach of the implied covenant of good faith and fair dealing. The case seeks damages in warrants to purchase our common stock and monetary damages for certain fees and expenses. The Sale Agreement with David Hall, Walter "JR" Wilcox, and Troy Stafford dated December 10, 2009 contains indemnification provisions relevant to this claim. We filed a Motion to Dismiss for lack of personal jurisdiction, but this motion was not granted by the court. We filed an Answer to the complaint in this case on October 10, 2012, and we have conducted discovery. Trial was previously set for November 4, 2013. On October 21, 2013, the trial was postponed with no new trial date having been set. On October 31, 2013, the judge ruled on our outstanding Motion for Summary Judgment, granting it as to the unjust enrichment claim and breach of the implied covenant of good faith and fair dealing claim, and denying it as to the breach of contract claim. We expect to proceed to trial on the breach of contract claim once a new trial date is set. In February 2014, we received notice from a third party seeking to intervene in the case in order to secure payment of a debt allegedly owed by the Plaintiff to the third party. On June 5, 2014, the court entered an order denying the motion to intervene. On May 29, 2014, the court put down a new scheduling order setting forth certain pre-trial deadlines with the final pre-trial conference being

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set for October 30, 2014. We expect the court to set a trial date that will be shortly after the final pre-trial conference. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

In August 2011, several purported class action lawsuits were filed against us in the United States District Court for the Eastern District of Tennessee. The lawsuits made similar claims and have been consolidated into one case, styled In re Miller Energy Resources, Inc. Securities Litigation. The suit names us, along with several of our current and former executive officers, Scott Boruff, Paul Boyd, Ford Graham, David Hall, and Deloy Miller, as defendants. The Plaintiffs allege two causes of action against the defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks money damages against us and the other defendants, and payment of the Plaintiffs' attorney's fees. We have filed a Motion to Dismiss the case, which was denied on February 4, 2014 as to all defendants save Ford Graham. On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, which is within the remaining policy limits of our director and officer insurance policy. The proposed settlement remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014.

On August 23, 2011, a derivative action was filed against us in Knox County Chancery Court. The case is styled Marco Valdez, derivatively on behalf Miller Energy Resources, Inc. v. Deloy Miller, Scott M. Boruff, Jonathan S. Gross, Herman Gettelfinger, David Hall, Merrill A. McPeak, Charles M. Stivers, Don A. Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. The suit alleged the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failure to maintain internal controls; (3) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (4) Unjust Enrichment; (5) Abuse of Control; Gross Mismanagement, and; (6) Waste of Corporate Assets. The Plaintiff sought unspecified money damages from the individual defendants, that we take certain actions with respect to our management, restitution to us, and the Plaintiff's attorney fees and costs. The Plaintiff agreed to stay this case awaiting a ruling on the plaintiff's appeal in the federal derivatives case in Lukas v. Miller Energy Resources, Inc., et al, as described in the next paragraph. The Plaintiff also agreed to voluntarily dismiss the case in the event the plaintiff's appeal in Lukas was denied. Following the dismissal of Lukas, on October 1, 2013, the Court entered an Order dismissing the case without prejudice on the motion of the Plaintiff. On October 24, 2013, we filed a Motion to Amend the Order of Dismissal as the agreement with the Plaintiff was that the case would be dismissed with prejudice if the Sixth Circuit Court of Appeals affirmed the dismissal of the Lukas case, which it has. On June 3, 2014, after reaching an agreement with the Plaintiff, we filed an amended agreed final order of dismissal with prejudice in this case.

On August 25, 2011, and August 31, 2011, two derivative actions were filed against us and our Board of Directors and former Chief Financial Officer in the United States District Court for the Eastern District of Tennessee. These cases were consolidated into Patrick P. Lukas, derivatively on behalf Miller Energy Resources, Inc. v. Merrill A. McPeak, Scott M. Boruff, Deloy Miller, Jonathan S. Gross, Herman Gettelfinger, David Hall, Charles M. Stivers, Don A. Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. As noted below, this case had been dismissed by the trial court, and that dismissal was unsuccessfully appealed by the plaintiffs. It contained substantially similar claims as Valdez. The suit alleged the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (3) Unjust Enrichment; (4) Abuse of Control; (5) Gross Mismanagement, and; (5) Waste of Corporate Assets. The Plaintiffs sought unspecified money damages from the individual defendants, to have us take certain actions with respect to our management, restitution to us, and the Plaintiffs' attorney fees and costs. We filed a Motion to Dismiss, which was granted on September 21, 2012. On October 16, 2012, a notice of appeal of this dismissal was filed by the Plaintiffs with the Sixth Circuit Court of Appeals. On September 19, 2013, the Court of Appeals affirmed the judgment of the District Court dismissing the case. On October 3, 2013, the Plaintiff filed a Motion for Rehearing En Banc. The Court denied the motion on January 8, 2014. The Plaintiffs had three months to file a petition to the Supreme Court of the United States, but did not do so. Therefore, these cases have ended.

On August 31, 2012, we terminated an agreement with Voorhees Equipment and Consulting, Inc. (“Voorhees”) for the construction and sale of the rig currently being used on the Osprey Platform, Rig 35, (the “Rig 35 Agreement”). We terminated the agreement based on our belief that Voorhees was in breach of its obligations thereunder. Voorhees later indicated its desire to arbitrate claims it believes it has under invoices arising between May 29, 2012 and August 31, 2012. We believed we had grounds to dispute liability with respect to some or all of those invoices, in addition to having certain counterclaims we expected to assert. The parties elected to engage a private arbitrator to settle this dispute (the “Voorhees Matter”) and conducted discovery. On September 18, 2013, we received a third-party complaint from Voorhees in connection with a lawsuit by Carlile Transportation Systems, Inc., in the Superior Court for the State of Alaska. The case is styled Carlile Transportation Systems, Inc. v. Voorhees Rig International, Inc. v. Cook Inlet Energy, LLC (the “Carlile Matter”). The dispute in the Carlile Matter related solely to unpaid transportation fees arising from the transportation of equipment for Rig 35. These fees were already the subject of the planned arbitration with Voorhees over the Voorhees Matter. As all disputes under the Rig 35 Agreement are subject to mandatory arbitration, we filed a motion to compel arbitration in the Carlile Matter, which the Court granted, along with an award of our legal costs incurred in connection with the Carlile Matter. On February 20, 2014, we reached an agreement in principle to settle the Voorhees Matter (including the transportation fees at issue in the Carlile Matter), and we entered into a settlement agreement which was effective as of May 12, 2014. We agreed to return to Voorhees the following equipment previously delivered to us under the Rig 35 Agreement, but which we subsequently replaced on that rig:

- An iron roughneck that we had to replace on Rig 35 due to mechanical unreliability; and
- A BOP stack originally included on Rig 35, but later removed and replaced with a better functioning replacement;

We also agreed to return to Voorhees two moving containers, left-over electrical equipment and tools belonging to Voorhees but left with CIE when Voorhees ceased working on Rig 35. No costs of defense or other cash payment are expected to be required of us in connection with this settlement, although we will pay the transportation costs of the equipment being returned. Accordingly, we have accrued our best estimate, based on the terms in the settlement agreement, of the potential loss on our consolidated balance sheet.

On April 4, 2013, we filed suit against a former contractor of CIE and its parent company (collectively “Cudd”) in the United States District Court for the District of Alaska at Anchorage. This case is styled Cook Inlet Energy, LLC v. Cudd Pressure Control Inc. and RPC, Inc. In our suit we are seeking declaratory relief and damages for breach of contract, breach of implied warrant of merchantability, breach of implied covenant of fitness for a particular purpose and breach of the implied covenant of good faith and fair dealing arising out of a dispute regarding certain equipment and services provided by Cudd on the Osprey Platform that did not meet our needs or expectations as promised. We have not yet determined the full amount of damages claimed. On May 29, 2013, Cudd filed its Answer denying our claims and including a counterclaim for equipment and services, totaling approximately $1,889, plus the costs of defense. We have filed our counteranswer and denied that these amounts are owed, in whole or in part. We are presently conducting discovery. Given the current stage of the proceedings with respect to this case, we believe that any loss would be limited to $1,889 plus the cost of defense, related to this matter. Based on the information currently available, we have accrued our best estimate of the potential loss on our consolidated balance sheet.

On February 7, 2014, we were served with a lawsuit filed by Vulcan Capital Corporation in the District Court for the Southern District of New York styled Vulcan Capital Corp. v. Miller Energy Resources, Inc. and PlainsCapital Bank. The suit asserts various causes of action against PlainsCapital Bank, and appears to assert the following causes of action against us: (1) Breach of Fiduciary Duty and (2) Concert of Action. The case stems from an agreement Plaintiff had with PlainsCapital Bank wherein Plaintiff secured certain loans by pledging four warrants to purchase our common stock that were issued as part of the employment package of Ford F. Graham, our former President. Upon Plaintiff’s default of the loan agreement, PlainsCapital presented the warrants to us for transfer, and, after requesting certain tenders required under Tennessee law, we registered the transfer of the warrants. We have retained counsel and we have filed a Motion to Transfer as the warrants have a valid exclusive forum clause that requires the case be tried in Knox County, Tennessee. In addition, PlainsCapital Bank has agreed to indemnify us for our first $500 of expenses related to this dispute. Given the current state of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

We are also party to various routine legal proceedings arising in the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

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 2014, 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 2014 and 2013. 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.

	2014		2013	
	High	Low	High	Low
First quarter	$5.28	$3.66	$5.29	$3.75
Second quarter	8.39	4.91	5.26	3.79
Third quarter	8.83	5.69	5.01	3.38
Fourth quarter	7.44	4.79	4.23	3.50

The closing price of our common stock, as reported on the New York Stock Exchange for July 7, 2014, was $6.07 per share. As of July 7, 2014, there were 46,076,707 shares of our common stock outstanding held by approximately 338 stockholders of record. The actual number of holders of our common stock is greater than the number of record holders and includes stockholders who are beneficial owners, but whose shares are held in street name by brokers and nominees.

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 First Lien RBL and Second Lien Credit Facility do not permit us to pay dividends on our common stock.

Information concerning securities authorized for issuance under equity compensation plans will be forth in the proxy statement relating to our fiscal 2014 annual meeting of stockholders, which is incorporated herein by reference.

Unregistered Sales of Equity Securities

In March 2014, we issued 50,000 shares of our common stock to a warrant holder upon exercise of a common stock purchase warrant to purchase 50,000 shares of our common stock with an exercise price of $1.00 per share in a private transaction exempt from registration under the Securities Act of 1933 in reliance on an exemption provided by Section 4(2) of that act. The recipient was an accredited or otherwise sophisticated investor who had such knowledge and experience in business matters and was capable of evaluating the merits and risks of the prospective investment in our securities. The recipient had access to business and financial information concerning our company.

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, 2014. 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

	2009	2010	2011	2012	2013	2014
Miller Energy Resources, Inc.	$100	$1,752	$1,748	$1,645	$1,152	$1,461
S&P's Composite 500 Stock Index	100	136	156	160	183	216
Dow Jones US Exploration & Production Index	100	144	186	159	177	226

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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, 2014, 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,				
	2014	2013	2012	2011	2010
Income Statement Data:					
Total revenues	$70,558	$34,801	$35,402	$22,842	$5,867
Net income (loss) attributable to common stockholders	(41,767)	(25,495)	(19,537)	(3,880)	250,941
Net income (loss) per common share:					
Basic	(0.94)	(0.60)	(0.48)	(0.11)	11.65
Diluted	(0.94)	(0.60)	(0.48)	(0.11)	8.34
Balance Sheet Data:					
Total assets	$766,822	$572,824	$536,389	$509,081	$500,342
Total debt	184,202	54,978	24,130	2,000	1,239
Weighted average common shares outstanding:					
Basic	44,445,556	42,682,685	40,811,308	36,112,286	21,537,677
Diluted	44,445,556	42,682,685	40,811,308	36,112,286	30,092,017

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

This discussion summarizes the significant factors affecting the consolidated financial statements, financial condition, liquidity, and cash flows of Miller Energy Resources, Inc., for the fiscal years ended April 30, 2014, 2013 and 2012. The following discussion and analysis should be read in conjunction with the consolidated financial statements and the notes included elsewhere in this Form 10-K.

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 - oil and 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 are focused 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 are 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 employs 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, when available, 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 continues to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We 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, assembling the right complement of personnel, and procuring the equipment 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 facilities and funds raised from sales of our Series C Preferred Stock and Series D Preferred Stock, including "at-the-market" public offerings to support our capital expenditures during fiscal 2014. For the fiscal year ended April 30, 2014, we reported notable achievements in several key areas. Highlights for fiscal 2014 and early fiscal 2015 include:

- Starting May 1, 2013, and periodically during the fiscal year, we issued 924,968 shares of our Series C Preferred Stock in "at-the-market" offerings pursuant to the October 12, 2012 At Market Issuance Sales Agreement ("Series C ATM Agreement") with MLV and Co. LLC ("MLV") and a prospectus supplement dated October 12, 2012 (issued

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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 $21.48 to $26.71 per share. We received net proceeds of $20,202 in connection with these sales.

- On May 10, 2013, we issued 500,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated May 7, 2013 and we received net proceeds of $10,320.
- Effective May 15, 2013, we entered into a new commercial gas sales agreement in the Cook Inlet region with Chugach Electric Associations, Inc., Alaska's largest electric utility. Contractual gas sales commenced during the month of May and have continued throughout the period. We have primarily delivered gas on the new agreement with production from the RU-3 and RU-4A wells in the Redoubt Shoals field.
- On June 19, 2013, we began drilling our Sword #1 well from our West McArthur River Production Facility in the Cook Inlet region. The Sword #1 well was completed as an extended reach well drilled directionally to approximately 19,000 feet in an adjacent fault block to the West McArthur River Field. The 3D seismic data shows a faulted four-way closure and an estimated 240-acre structure with an estimated ultimate recovery ("EUR") of approximately 800,000 barrels of oil from the Sword #1 well.
- On June 20, 2013, we brought a new oil well, RU-2A, into production. This well is a sidetrack of a previously producing oil well, RU-2. After clearing the well of drilling fluids from the sidetrack, a subsequent well test showed an initial gross production of 1,281 barrels of oil per day with a water cut of 19%. The rate of production has averaged 926 barrels of oil per day through April 30, 2014.
- On July 2, 2013, we issued 335,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated June 27, 2013 and we received net proceeds of $6,655.
- On July 22, 2013, we announced that our Board of Directors appointed David M. Hall to Chief Operating Officer ("COO"). Mr. Hall has been the Chief Executive Officer of our wholly-owned Alaskan operating subsidiary, CIE, since 2009 and will continue in that capacity. In his new role as COO, Mr. Hall will oversee our drilling operations in both Alaska and Tennessee.
- On July 25, 2013, we elected a new independent director, Marceau Schlumberger, to our board of Directors. Mr. Schlumberger has nearly twenty years of investment banking experience, including international and domestic mergers and acquisitions, restructuring, strategic analysis, and financial experience.
- On August 5, 2013, we entered into the Sixth Amendment to our credit facility with Apollo (the "Prior Credit Facility") which allowed us to borrow an additional $20,000 at a temporarily reduced interest rate of 9%. For additional information on the Sixth Amendment and the Prior Credit Facility, refer to Note 4 - Debt.
- On August 17, 2013, we successfully brought our RU-1A oil well online. The well is a sidetrack of a previously producing oil well, RU-1. The newly completed well displayed an initial gross production rate of 700 barrels of oil per day and an approximate water cut of 5%. The rate of production has averaged 476 barrels of oil per day through April 30, 2014.
- On September 30, 2013, we completed our initial public offering of our Series D Preferred Stock, issuing 1,000,000 shares at $25.00 per share with net proceeds of $23,125.
- On September 30, 2013, we completed negotiations for a multi-year gas sales agreement with Chugach Electric Association, Inc., which expanded upon the short-term contract signed in May. The contract was submitted to the Regulatory Commission of Alaska and was approved on November 25, 2013.
- On October 12, 2013, we brought our RU-5B oil well online. The rate of production has averaged 130 barrels of oil per day through April 30, 2014.
- On October 15, 2013, we brought our Brimstone H-1 well online in Tennessee. Similar to our other horizontal wells, this well requires additional testing. At April 30, 2014, the well had produced 2,503 net barrels of oil.
- On October 23, 2013, we reached total depth on our Sword #1 well. On November 20, 2013, we brought the well online. Its initial gross production rate was 883 barrels of oil per day. At April 30, 2014, the well was producing approximately 403 barrels of oil per day.

- On October 24, 2013, we received an Underground Injection Control ("UIC") permit from the EPA. We intend to re-inject gas into a vertical well adjacent to our CPP H-1 horizontal well in Tennessee to maintain reservoir pressure and hopefully increase production.
- On October 31, 2013, we completed our workover of the RU-D1 disposal well to prepare for additional drilling activity on the Osprey platform.

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- On October 31, 2013, the Susitna #2 License expired. Prior to expiration, we received confirmation from the State of Alaska that we had met our work commitment under the Susitna #2 License and were eligible to convert acreage under the license to leases. We applied for conversion and requested issuance of the proposed leases in three groups. The first group of leases consisting of a total of 47,000 acres were issued with an effective date of November 1, 2013. The second and third group of leases consisting of a total of 120,900 acres were issued with an effective date of January 1, 2014. Upon award, an annual rental fee of $3.00 per acre was paid to the State of Alaska. The annual rental fee for all three groups of leases totals $504.
- On November 22, 2013, we entered into an agreement to acquire the North Fork Properties in the Cook Inlet region and the Anchor Point Equity for $64,975, subject to customary adjustments, with approximately $5,000 to be paid in our Series D Preferred Stock (213,586 shares).
- Beginning November 26, 2013 and periodically thereafter, we issued 70,448 shares of our Series D Preferred Stock in "at-the-market" offerings pursuant to the October 17, 2013 At Market Issuance Sales Agreement ("Series D ATM Agreement") and a prospectus supplement dated October 17, 2013 (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 ranging from $23.95 to $24.38 per share. We received net proceeds of $1,654 in connection with these sales.
- On November 28, 2013, we spudded our WMRU-8 oil well from our West McArthur River Production Facility. WMRU-8 was drilled as a directional well into a separate fault block to the main producing structure in the West McArthur River Field. The well reached a total depth of 15,536 feet on February 12, 2014 after successfully drilling and logging the Jurassic and West Forelands secondary targets.
- On February 3, 2014, we entered into a new loan agreement with Apollo, as administrative agent, which set forth the terms of the Second Lien Credit Facility. Proceeds from the new $175,000 term credit facility were used to repay the previously existing credit facility, repay all obligations to Miller Energy Income 2009-A, LP, acquire the North Fork Properties and provide working capital.
- On February 6, 2014, we entered into the Trans-Foreland Pipeline Development Agreement with Tesoro Alaska Company and Trans-Foreland Pipeline Company, LLC. This agreement allows for the construction of the Trans-Foreland Pipeline to connect our Kustatan Production Facility on the west side of the Cook Inlet to the Kenai Pipe Line Company tank farm on the east side. Completion of the pipeline would provide numerous advantages to us, including reduced transportation cost and delays.
- On February 12, 2014, our Board of Directors appointed John M. Brawley as our Chief Financial Officer. In addition, the Board of Directors approved a change in the title of David J. Voyticky to President, as he previously held the title of President and Acting Chief Financial Officer.
- On March 31, 2014, we purchased ten wells and associated infrastructure in Tennessee.
- On April 17, 2014, we held our annual meeting of shareholders at which Bob G. Gower, Joseph T. Leary and William B. Richardson were elected to our Board of Directors as three new independent directors. The Board now consists of eight directors, six of whom are independent.
- On April 17, 2014, we received a construction permit from the State of Tennessee for the construction of a gas processing facility. Once operational, the facility will allow us to process high BTU gas, strip the liquids, and produce the lower BTU gas into the sales line without blending. The operational target date is July 2014.
- On May 8, 2014, we entered into the Merger Agreement with Savant subject to due diligence and regulatory approval for $9,000. Savant currently owns, and we would acquire as a result of this merger, a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. In additional to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located in the North Slope. We expect the transaction to close by December 2014, following regulatory approval.
- On June 2, 2014 we entered into a credit agreement, among the Company, as borrower, and KeyBank National Association, as administrative agent. In addition to KeyBank, the syndicate includes CIT Finance LLC, Mutual of Omaha Bank and OneWest Bank N.A. The First Lien Loan Agreement provides for a $250,000 senior secured,

reserve-based revolving credit facility $60,000 of which was made available to us on the closing date. Amounts outstanding under the First Lien RBL are priced on a sliding scale, based on LIBOR plus 300 to 400 basis points, depending upon the level of borrowing. We drew $20,000 on the closing date under the First Lien RBL to provide working capital for development drilling in Alaska.

- On June 24, 2014, we drew an additional $10,000 under the First Lien RBL to provide working capital for development drilling in Alaska.
- On June 24, 2014, we received the proceeds of Alaska production credits totaling $21,837 from the State of Alaska.

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- On July 4, 2014, we entered into a Purchase and Sale Agreement with Teras Oilfield Support Limited ("Teras") for the right to purchase the Glacier Drilling Rig #1, a Mesa 1000 carrier-mounted land drilling rig (the "Glacier Rig"), and related equipment (the "Glacier PSA"). The Glacier PSA is dated as of July 3, 2014, but was signed by Teras the following day. A payment of $700 was required in connection with the execution and delivery of the Glacier PSA. An additional payment of $6,300 will be due if the sale is finalized.

Fiscal 2015 Outlook

As we head into fiscal 2015, we believe our inventory of recompletion, workovers, and exploration and development projects offers numerous growth opportunities. Subsequent to April 30, 2014, we have continued our onshore and offshore drilling programs. Since the year end, we have brought the WMRU-2B oil well online and have begun drilling the West Foreland #3 gas well. We have also received the second commingling permit for our Sword-1 well, with all three zones currently producing. Following the West Foreland #3 well, we plan to drill the nearby Sabre prospect. The Sabre-1 well will be drilled in the fall, following completion of upgrades to the newly acquired Rig 36.

On the Osprey platform we are continuing to drill the RU-9 South step-out well using Rig 35 and expect to complete the well during the summer of 2014. Following successful completion of the well, we will assess the next development activity on the Osprey platform and plan to drill our RU-12 grassroots oil well located in the Northern Fault.

On the east side of the Cook Inlet, we also have several development projects at North Fork, which we expect will also contribute to production in fiscal 2015.

Beyond our existing assets, on May 14, 2014 we announced our intent to acquire Savant, subject to due diligence and regulatory approval, for $9,000 in cash. Savant would become a wholly-owned subsidiary of Miller. Through Savant, Miller would own a 67.5% working interest in the Badami Unit, with ASRC Exploration, LLC remaining as a 32.5% working interest partner. Miller would also obtain a 100% working interest in nearby exploration leases. As of May 2014, these assets would add approximately 600 bopd net of current production and ownership of midstream assets located in the North Slope with a design capacity of 38,500 bopd and 50 miles of pipeline. We are currently evaluating development plans and opportunities for joint ventures in the Badami Unit.

No assurance can be made regarding the success of these development and recompletion efforts. Our current 2015 capital budget is approximately $200,000 and excludes potential development activities associated with the pending Savant acquisition. The majority of this budget is expected to be spent on projects in Cook Inlet, Alaska.

Due to the uncertainty associated with changes in commodity prices and production, 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 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, rig availability, access to capital, weather and regulatory approval.

On June 2, 2014, we entered into the First Lien RBL contemplated by the Second Lien Credit Facility, with an initial borrowing base of $60,000. At closing we drew $20,000 and on June 24, 2014 we drew an additional $10,000. The remaining availability under the First Lien RBL was $30,000 as of July 7, 2014.   As reserves grow, the borrowing base may be adjusted to provide additional capital to fund our development program. We note that the borrowing base of our First Lien RBL is calculated at the discretion of the lenders based on our proved reserves, commodity prices, total debt and other factors at their sole discretion. As such, it is possible our borrowing base could be reduced in the future.

On June 24, 2014, we received proceeds of Alaska production credits totaling $21,837 from the State of Alaska. Additionally, following our year end, we entered into a capital lease for the newly purchased Rig 36, for a total of $3,250 which can be expanded up to $5,000, as we upgrade Rig 36.

Effective as of July 4, 2014, we entered into a Purchase and Sale Agreement with Teras which grants us the right to purchase the Glacier Rig and the Glacier PSA. The Glacier PSA is dated as of July 3, 2014, but was signed by Teras the following day. A payment of $700 was required in connection with the execution and delivery of the Glacier PSA, which we are entitled to have refunded if we fail to close by August 8, 2014, if it should be determined that Teras lacks clear title to the Glacier Rig, there are liens or encumbrances (other than immaterial defects in title or liens to which we consented) or if the Glacier Rig is affected by a significant casualty prior to closing. An additional payment of $6,300 will be due if the sale is finalized.

We believe that we will be able 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 with State of Alaska production credits, potential joint ventures, and through the debt, equity and preferred equity capital markets.

Although we have the ability to sell our Series C and Series D Preferred Stock in additional “at-the-market” offerings during fiscal 2015, subject to certain limits under our First Lien RBL, 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. 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,				
	2014	% Variance	2013	% Variance	2012
Oil sales:					
Cook Inlet	$62,018	122 %	$27,891	(9)%	$30,566
Appalachian region	2,482	60	1,556	18	1,314
Total	$64,500	119	$29,447	(8)	$31,880
Natural gas sales:					
Cook Inlet	$4,588	11,090	$41	(69)	$134
Appalachian region	381	(11)	427	(11)	479
Total	$4,969	962	$468	(24)	$613
Other:					
Cook Inlet	$379	(90)	$3,950	226	$1,212
Appalachian region	710	(24)	936	(45)	1,697
Total	$1,089	(78)	$4,886	68	$2,909
Total revenues	$70,558	103 %	$34,801	(2)%	$35,402

Net Production

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Oil volume - bbls:					
Cook Inlet	659,188	139 %	275,658	(15)%	325,756
Appalachian region	25,513	29	19,825	19	16,655
Total	684,701	132	295,483	(14)	342,411
Natural gas volume[1]- mcf:					
Cook Inlet	682,831	9,004	7,500	(84)	45,985
Appalachian region	110,876	(11)	125,238	(4)	130,609
Total	793,707	498	132,738	(25)	176,594
Total production[2] - boe:					
Cook Inlet	772,993	179	276,908	(17)	333,420
Appalachian region	43,993	8	40,698	6	38,423
Total	816,986	157 %	317,606	(15)%	371,843

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,				
	2014	% Variance	2013	% Variance	2012
Average oil sales price - per barrel:					
Cook Inlet	$101.20	(1)%	$102.74	9 %	$93.83
Appalachian region	92.73	10	83.92	6	78.89
Total	100.85	(1)	101.53	9	93.10
Average natural gas sales price - per mcf:					
Cook Inlet	6.72	68	3.99	37	2.92
Appalachian region	3.43	1	3.41	(7)	3.66
Total	6.26	78	3.52	1	3.47

Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside 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 2014 were 1% below fiscal 2013, decreasing from an average of $101.53 per bbl in 2013 to $100.85 per bbl in 2014.

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. During fiscal 2014, realized natural gas prices averaged $6.26 per mcf, compared with $3.52 per mcf for the same period in the prior year. The increase in the average realized gas prices primarily resulted from natural gas sales at higher realized prices as a result of the acquisition of the North Fork Properties.

Oil Sales

2014 vs. 2013. During 2014, oil sales totaled $64,500, which is 119% higher than 2013. The increase resulted from a 132% increase in production partially offset by a 1% decrease in realized oil prices. Oil sales represented 91% of our consolidated total revenues in 2014 and 84% of our equivalent production.

Oil production increased 389,218 bbls, driven by a 383,530 bbl increase in the Cook Inlet region and a 5,688 bbl increase in the Appalachian region. The production increase in the Cook Inlet region resulted from RU-1A, RU-2A and RU-5B in our Redoubt Shoals field and our new Sword #1 being online during 2014.

The difference between net barrels sold and net barrels produced is approximately equal to the change in quantity of our crude oil inventory balance during the period. Although we attempt to minimize crude oil inventory balances, shipping schedules in the Cook Inlet region are beyond our control and occasionally require us to store crude oil. In addition, we are required to maintain certain inventory levels in third party pipelines and storage facilities. As noted in the following table, we experienced an above average increase in inventory levels during fiscal 2014, which significantly reduced the potential revenue that may have resulted from our increased oil production during the current period. The increase in our inventory balance primarily resulted from shipping schedules and a requirement to maintain increased inventory levels in third party facilities in the Cook Inlet region.

	April 30, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	30,130	12,148	42,278
Gross production	788,324	25,513	813,837
Gross sales	(732,939)	(26,766)	(759,705)
Pipeline adjustments	(3,020)	—	(3,020)
Ending inventory balance	82,495	10,895	93,390

Net change in inventory	52,365	(1,253	) 51,112

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2013 vs. 2012. During 2013, oil sales totaled $29,447, 8% lower than 2012, driven by a 9% increase in average realized prices and a 14% decrease in production. Oil sales represented 85% of our consolidated total revenue and 93% of our equivalent production in 2013.

Oil production decreased 46,928 bbls, driven by a 50,098 bbls decrease in the Cook Inlet region, offset by a 3,170 bbls increase in the Appalachian region. The production decrease in the Cook Inlet region resulted from wells being offline during certain portions of the year, a normal decline curve, and fluctuations in shipping schedules.

Natural Gas Sales

2014 vs. 2013. During 2014, natural gas sales totaled $4,969, which is 962% higher than 2013. The increase resulted from the acquisition of the North Fork Properties and from selling natural gas in excess of our fuel gas needs from our RU-3 and RU-4A wells in the Cook Inlet region which increased production by 498%. The North Fork Properties acquisition contributed $4,124 to natural gas sales during 2014. Natural gas represented 7% of our consolidated total revenues in 2014 and 16% of our equivalent production.

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

Other

2014 vs. 2013. 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 2014 and 2013, other revenues totaled $1,089, or 2%, and $4,886, or 14%, respectively, of our consolidated total revenues. The decrease in other revenues primarily resulted from the completion of the road and pad building project in the Cook Inlet region which contributed to our revenue in 2013.

2013 vs. 2012. 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.

Cost and Expenses

The table below presents a comparison of our expenses for the years ended April 30, 2014, 2013 and 2012:

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Lease operating expense	$20,187	(9)%	$22,288	97%	$11,305
Transportation costs	5,599	132	2,410	(32)	3,556
Cost of other revenues	1,147	(73)	4,189	352	926
General and administrative	31,744	22	26,067	(12)	29,718
Alaska carried-forward annual loss credits, net	(16,342)	400	(3,268)	N/A	—
Exploration expense	2,009	38	1,458	17	1,241
Depreciation, depletion, and amortization	33,528	155	13,170	(1)	13,310
Accretion of asset retirement obligation	1,239	38	900	(16)	1,072
Other operating (income) expense, net	2,140	(3,444)	(64)	(90)	(641)
Total costs and expenses	$81,251	21%	$67,150	11%	$60,487

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Lease Operating Expense

The table below presents a comparison of our lease operating expense for the years ended April 30, 2014 and 2013:

	For the Year Ended April 30,			
	2014	2013	$ Variance	% Variance
Lease operating expense	$20,187	$22,288	$(2,101)	(9)%
Net production - boe[1]	816,986	317,606		
Lease operating expense per boe produced	$24.71	$70.17	$(45.46)	(65)%

1 Net production for fiscal 2014 and 2013 excludes 152,373 and 57,123 boe of fuel gas, respectively.

Lease operating expense decreased $2,101 from fiscal 2013, or 9%. The decreased lease operating expense is primarily attributable to decreases in workover cost related to our RU-1 and RU-7 wells in the Redoubt Shoals field in the Cook Inlet region slightly offset by increases in our production. The increased production creates marginal increases in labor and camp facility costs and well maintenance; however, the majority of our production costs are fixed. For the year ended April 30, 2014 our lease operating expense per boe produced was $24.71 as compared to $70.17 for the year ended April 30, 2013. We expect our lease operating expense per boe produced to continue to decline as production increases.

The table below presents a comparison of our lease operating expense for the years ended April 30, 2013 and 2012:

	For the Year Ended April 30,			
	2013	2012	$ Variance	% Variance
Lease operating expense	$22,288	$11,305	$10,983	97%
Net production - boe[1]	317,606	371,843		
Lease operating expense per boe produced	$70.17	$30.40	$39.77	131%

1 Net production for fiscal 2013 and 2012 excludes 57,123 and 33,956 boe of fuel gas, respectively.

Lease operating expense increased $10,983 from fiscal 2012, or 97%. 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. As the majority of our operating costs are fixed, we did not experience a proportionate decrease in cost from the declines in production.

Transportation Costs

2014 vs. 2013. Transportation costs increased $3,189 from fiscal 2013, or 132%. Increased oil transportation costs were due to increased production, and increased gas transportation costs were primarily due to the acquisition of the North Fork Properties for which we incurred $1,403 in gas transportation costs.

2013 vs. 2012. Transportation costs decreased $1,146 from fiscal 2013, or 32%. The decrease is primarily due to decreased production and a decrease in contractual oil transportation charges.

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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 2014, we experienced decreases in cost of other revenues in the Cook Inlet region as we had fewer projects during the year.

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Direct labor	$665	(75)%	$2,656	292 %	$677
Equipment	121	(84)	775	100	—
Repairs	316	(47)	598	572	89
Insurance	—	(100)	91	100	—
Other	45	(35)	69	(57)	160
Total	$1,147	(73)%	$4,189	352 %	$926

2014 vs. 2013. During 2014, cost of other revenues decreased 73% to $1,147. A substantial portion of this decrease is related to direct labor and equipment costs incurred as a result of a road and pad building contract that was completed in 2013.

2013 vs 2012. During 2013, cost of other revenues increased 352% to $4,189. A substantial portion of this increase was related to direct labor and equipment costs incurred as a result of a road and pad building contract that was completed in 2013.

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,				
	2014	% Variance	2013	% Variance	2012
Stock-based compensation	$8,684	(14)%	$10,132	(28)%	$14,072
Professional fees	10,955	75	6,248	37	4,561
Salaries	5,050	35	3,732	12	3,330
Employee benefits	1,759	(25)	2,357	(38)	3,824
Travel	2,001	15	1,744	3	1,693
Other	3,295	78	1,854	(17)	2,238
Total	$31,744	22 %	$26,067	(12)%	$29,718

2014 vs 2013. G&A expenses increased $5,677 from fiscal 2013, or 22%. Stock-based compensation decreased 14% from the same period in the prior year, primarily due to fewer awards granted during our 2014 fiscal year as compared to the previous fiscal year. Salaries increased 35% from the same period in the prior fiscal year as we continue to expand our engineering and accounting staff. The increase in professional fees of 75% results from additional cost related to corporate governance, litigation matters and investor relations activities.

2013 vs. 2012. G&A expenses decreased $3,651 from fiscal 2012, or 12%. The decrease to stock-based compensation of 28% was primarily due to significantly fewer awards being granted during our 2013 fiscal year as compared to our 2012 fiscal year. Salaries increased 12% from fiscal 2012 to fiscal 2013 as we continue to expand our engineering, legal and accounting staff. The increase in professional fees of 37% resulted from additional cost related to corporate governance and investor relations activities.

Alaska Carried-Forward Annual Loss Credits, Net

2014 vs. 2013. During 2014, Alaska carried-forward annual loss credits, net increased $13,074, or 400%. Alaska carried-forward annual loss credits, net are generated when there is an annual loss per the State of Alaska tax statues. Increased expenses and increased drilling activity led to higher annual losses per the State of Alaska tax statutes for carried-forward annual loss credits.

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2013 vs. 2012. During 2013, Alaska carried-forward annual loss credits, net increased $3,268, or 100%. Increased expenses and increased drilling activity led to higher annual losses per the State of Alaska tax statutes for carried-forward annual loss credits.

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.

2014 vs. 2013. Exploration expense increased 38% to $2,009 primarily due to an increase in delay rentals as compared to the same period in the prior year.

2013 vs. 2012. Exploration expense increased 17% to $1,458 primarily due to the timing of impairments of 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,					
	2014	2013	2012	2014	2013	2012
				(Per boe)		
Depletion:						
Cook Inlet region	$28,316	$8,460	$11,790	$36.63	$26.80	$29.42
Appalachian region	976	1,343	747	22.19	22.61	19.45
	29,292	9,803	12,537	35.85	26.16	28.55
Depreciation:						
Cook Inlet region	3,506	2,591	169	NM	NM	NM
Appalachian region	730	776	604	NM	NM	NM
	4,236	3,367	773	4.37	8.99	1.76
Total DD&A	$33,528	$13,170	$13,310	$40.22	$35.15	