MILLER ENERGY RESOURCES, INC.
Form 10-Q
December 10, 2014

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

FORM 10-Q

(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended October 31, 2014
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________________ to __________________________

Commission file number: 001-34732

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

Tennessee (State or other jurisdiction of incorporation or organization)	62-1028629 (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)

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

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No 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. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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 Exchange Act)
Yes o No þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. The number of shares of common stock issued and outstanding as of November 24, 2014 was 46,634,471.

TABLE OF CONTENTS

Table of Contents

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

MILLER ENERGY RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)
(Dollars in thousands, except share data)

	October 31, 2014	April 30, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$14,484	$5,749
Restricted cash	1,147	679
Accounts receivable, net of allowances of $303 and $252	8,228	6,409
Alaska production credits receivable, net of allowances of $4,187 and $7,124	37,684	49,121
Inventory	7,778	5,102
Prepaid expenses and other	5,978	3,852
Short-term portion of derivative instruments	7,222	88
Deferred income taxes	2,666	—
Assets held for sale	5,308	236
Total current assets	90,495	71,236
OIL AND GAS PROPERTIES, NET	362,555	644,827
EQUIPMENT, NET	54,230	35,369
OTHER ASSETS:		
Land	1,848	1,848
Restricted cash, non-current	14,364	12,075
Deferred financing costs, net	2,385	803
Long-term portion of derivative instruments	2,159	26
Other assets	783	638
Total assets	$528,819	$766,822
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$47,252	$38,836
Accrued expenses	18,749	20,446
Short-term portion of derivative instruments	—	3,315
Deferred income taxes	—	2,858
Current portion of long-term debt and capital leases	24,672	9,459
Liabilities associated with assets held for sale	1,495	—
Total current liabilities	92,168	74,914
OTHER LIABILITIES:		
Deferred income taxes	20,197	139,768
Asset retirement obligation	22,276	22,872
Long-term portion of derivative instruments	—	4,006
Long-term debt and capital leases, less current portion	194,346	174,743
Other	29	—
Total liabilities	329,016	416,303

MEZZANINE EQUITY:		
Series C Cumulative Preferred Stock, redemption amount of $78,124, 3,250,000 shares authorized, 3,069,968 shares issued and outstanding as of October 31, 2014 and April 30, 2014	69,154	67,760
STOCKHOLDERS' EQUITY:		
Series D Cumulative Redeemable Preferred Stock, redemption amount of $53,276 and $32,378, 4,000,000 shares authorized, 2,112,458 and 1,070,448 shares issued and outstanding as of October 31, 2014 and April 30, 2014, respectively	49,791	30,041
Series D Cumulative Redeemable Preferred Stock, 0 and 213,586 shares held in escrow as of October 31, 2014 and April 30, 2014, respectively	—	(5,000)
Common stock, $0.0001 par, 500,000,000 shares authorized, 46,599,471 and 45,756,697 shares issued and outstanding as of October 31, 2014 and April 30, 2014, respectively	5	4
Additional paid-in capital	109,829	98,788
Retained earnings (accumulated deficit)	(28,976)	158,926
Total stockholders' equity	130,649	282,759
Total liabilities and stockholders' equity	$528,819	$766,822

See accompanying notes to the condensed consolidated financial statements.

1

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(Dollars in thousands, except share data)

	Three Months Ended October 31,		Six Months Ended October 31,	
	2014	2013	2014	2013
REVENUES:				
Oil sales	$18,044	$18,406	$37,345	$30,664
Natural gas sales	5,865	283	11,662	553
Other	267	107	548	587
Total revenues	24,176	18,796	49,555	31,804
OPERATING EXPENSES:				
Lease operating expense	8,963	5,176	15,589	10,816
Transportation costs	(442)	987	2,542	1,612
Cost of purchased gas sold	1,284	—	2,256	—
Cost of other revenue	325	304	665	588
General and administrative	17,901	7,145	27,412	13,505
Alaska carried-forward annual loss credits, net	323	—	(2,732)	—
Exploration expense	166,812	148	167,108	434
Depreciation, depletion and amortization	20,082	9,018	37,060	14,710
Accretion of asset retirement obligation	351	301	697	598
Impairment of proved properties	113,734	—	113,734	—
Other operating expense, net	—	—	4	—
Total operating expense	329,333	23,079	364,335	42,263
OPERATING LOSS	(305,157)	(4,283)	(314,780)	(10,459)
OTHER INCOME (EXPENSE):				
Interest expense, net	(3,619)	(1,363)	(6,418)	(3,644)
Gain (loss) on derivatives, net	23,089	(4,190)	16,186	(7,266)
Other income (expense), net	33	(2)	155	(16)
Total other income (expense)	19,503	(5,555)	9,923	(10,926)
LOSS BEFORE INCOME TAXES	(285,654)	(9,838)	(304,857)	(21,385)
Income tax benefit	117,746	4,850	125,095	9,469
NET LOSS	(167,908)	(4,988)	(179,762)	(11,916)
Accretion of Series C and D preferred stock	(913)	(665)	(1,734)	(1,118)
Series C and D preferred stock cumulative dividends	(3,459)	(2,632)	(6,406)	(4,668)
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(172,280)	$(8,285)	$(187,902)	$(17,702)
LOSS PER COMMON SHARE:				
Basic	$(3.71)	$(0.19)	$(4.07)	$(0.40)
Diluted	$(3.71)	$(0.19)	$(4.07)	$(0.40)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:				
Basic	46,367,131	44,081,775	46,147,038	43,768,414
Diluted	46,367,131	44,081,775	46,147,038	43,768,414

See accompanying notes to the condensed consolidated financial statements.

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
(Unaudited)
(Dollars in thousands, except share data)

	Series D Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total
	Shares	Amount	Shares	Amount			
Balance at April 30, 2014	1,070,448	$25,041	45,756,697	$4	$98,788	$ 158,926	$282,759
Net loss	—	—	—	—	—	(179,762)	(179,762)
Series C preferred stock dividends	—	—	—	—	—	(4,126)	(4,126)
Accretion of Series C preferred stock	—	—	—	—	—	(1,394)	(1,394)
Issuance of Series D preferred stock	1,042,010	24,410	—	—	—	—	24,410
Series D preferred stock dividends	—	—	—	—	—	(2,280)	(2,280)
Accretion of Series D preferred stock	—	340	—	—	—	(340)	—
Issuance of equity for services	—	—	—	—	574	—	574
Issuance of equity for compensation	—	—	521,420	—	9,059	—	9,059
Exercise of equity rights	—	—	321,354	1	1,408	—	1,409
Balance at October 31, 2014	2,112,458	$49,791	46,599,471	$5	$109,829	$ (28,976)	$130,649

See accompanying notes to the condensed consolidated financial statements.

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Six Months Ended October 31, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(179,762)	$(11,916)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	37,060	14,710
Amortization of deferred financing fees and debt discount	799	754
Expense from issuance of equity	10,113	3,574
Non-cash exploration expenses	166,303	193
Impairment of proved properties	113,734	—
Deferred income taxes	(125,095)	(9,556)
Derivative contracts:		
(Gain) loss on derivatives, net	(16,186)	7,266
Cash settlements paid	(402)	(1,782)
Alaska carried-forward annual loss credits, net	(2,732)	—
Accretion of asset retirement obligation	697	598
Other, net	309	930
Changes in operating assets and liabilities (excluding effects of acquisitions):		
Receivables	17,883	383
Inventory	28	1,487
Prepaid expenses and other assets	817	(1,420)
Accounts payable, accrued expenses and other	1,917	(1,047)
NET CASH PROVIDED BY OPERATING ACTIVITIES	25,483	4,174
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures for oil and gas properties	(78,215)	(66,171)
Proceeds from Alaska expenditure and exploration based credits	36,809	9,668
Prepayment of drilling costs	—	(2,192)
Deposits for potential acquisition	(3,000)	—
Purchase of equipment and improvements	(16,359)	(950)
NET CASH USED IN INVESTING ACTIVITIES	(60,765)	(59,645)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Cash dividends	(5,863)	(3,258)
Payments on debt	(14,611)	—
Proceeds from borrowings	46,000	20,000
Proceeds from capital lease obligations	3,250	—
Principal payments on capital lease obligations	(299)	—
Debt acquisition costs	(2,076)	(1,900)
Issuance of preferred stock	20,376	56,333
Equity issuance costs	(1,412)	(3,683)
Exercise of equity rights	1,409	2,283
Restricted cash	(2,757)	5,027
Other	—	3

NET CASH PROVIDED BY FINANCING ACTIVITIES	44,017	74,805
NET CHANGE IN CASH AND CASH EQUIVALENTS	8,735	19,334
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	5,749	2,551
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$14,484	$21,885
SUPPLEMENTARY CASH FLOW DATA:		
Cash paid for interest	$11,914	$5,712
SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Increase in capital expenditures included in accounts payable and accrued expenses	$3,951	$15,325
Reduction of oil and gas properties and equipment from applications for Alaska expenditure and exploration based credits	$41,843	$5,642
Accretion of preferred stock	$1,734	$1,118
Issuance of Series D Preferred Stock for Anchor Point Pipeline	$5,446	$—

See accompanying notes to the condensed consolidated financial statements.

Table of Contents

MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

1. ORGANIZATION AND BASIS OF PRESENTATION

Overview

Unless specifically set forth to the contrary, when used in this report, the terms "Miller Energy Resources," the "Company," "we," "us," "ours," "MER," "Miller," and similar terms refer 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, Cook Inlet Energy, LLC ("CIE"), and Anchor Point Energy, LLC ("Anchor Point Pipeline") collectively.

We are an independent exploration and production company that utilizes seismic data and other technologies for the geophysical exploration, development and production of oil and natural gas wells in southcentral Alaska, including the Cook Inlet and Kenai Peninsula. The accounting policies used by us and our subsidiaries reflect industry practices and conform to U.S. generally accepted accounting principles ("GAAP").

Basis of Presentation

The accompanying condensed consolidated financial statements are presented in accordance with GAAP and, in the opinion of management, include all adjustments (consisting only of normal recurring adjustments) necessary for a fair statement of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted under Securities and Exchange Commission ("SEC") rules and regulations. The results reported in these condensed consolidated financial statements are not necessarily indicative of the financial position or operating results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the audited consolidated financial statements and notes thereto included in Item 8 of Part II of the Company's Annual Report on Form 10-K for the year ended April 30, 2014, which was filed with the SEC on July 14, 2014, and amended on July 15, 2014.

Certain amounts in prior fiscal years have been reclassified to conform with the presentation adopted in the current year.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those disclosed in our Annual Report on Form 10-K for the year ended April 30, 2014.

Principles of Consolidation

The accompanying condensed consolidated financial statements include our consolidated accounts after elimination of intercompany balances and transactions. The condensed consolidated financial statements also include the accounts of all investments in which we, either through direct or indirect ownership, have more than a 50% interest or significant influence over the management of those entities.

Use of Estimates

The preparation of financial statements requires us to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances. The estimates are evaluated by management on an ongoing basis and the results of these evaluations form a basis for making decisions about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, we believe that the estimates used in the preparation of our financial statements are reasonable.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas properties. Under this method, exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged against earnings as incurred. Acquisition costs and costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the area as a result of drilling the well. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to exploration expense.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities, and associated asset retirement costs are depleted using the unit-of-production method based on total estimated proved developed reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms, and associated asset retirement costs are depleted using the unit-of-production method based on total estimated proved reserves.

When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future net cash flows, calculated using the Company's estimate of future oil and natural gas prices, operating expenses and production, to the net book value of the proved properties on a field by field basis. If the sum of the expected undiscounted future net cash flows is less than the net book value of the proved properties, an impairment loss is recognized for the excess, if any, of the net book value over its estimated fair value. See Note 6 for a discussion of asset impairments.

Acquisition costs of unproved properties are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment based on our current exploration plans, and a valuation allowance is provided if impairment is indicated. Costs of expired or abandoned leases are charged to expense, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties are included in oil and gas operating expense and impairments of unsuccessful leases are included in exploration expense.

Loss Per Share

We determine basic income (loss) per share and diluted income (loss) per share in accordance with the provisions of ASC 260, “Earnings Per Share.” Basic income (loss) per share excludes dilution and is computed by dividing earnings available to common stockholders by the weighted-average number of common shares outstanding for the period. The calculation of diluted earnings (loss) per share is similar to that of basic earnings per share, except that the denominator is increased, if net income is positive, to include the number of additional common shares that would have been outstanding if all potentially dilutive common shares, such as those issuable upon the exercise of stock options and warrants, had been exercised. We compute the numerator for basic income (loss) by subtracting accretion of preferred stock and cumulative preferred stock dividends from net income (loss) to arrive at net income (loss) attributable to common stockholders. Preferred stock dividends include dividends declared on preferred stock (regardless of whether the dividends have been paid) and dividends accumulated for the period on cumulative preferred stock (regardless of whether the dividends have been declared). As of October 31, 2014, our cumulative preferred dividends were $6,406.

Deferred Escalating Minimum Rent

Certain of our operating leases contain predetermined fixed escalations of the minimum rentals during the term of the lease, which includes option periods where failure to exercise such options would result in an economic penalty. For these leases, we recognize the related rental expense on a straight-line basis over the life of the lease, beginning with the point at which we obtain control and possession of the leased properties, and record the difference between the amounts charged to operations and amounts paid as deferred escalating minimum rent. Any lease incentives received are deferred and subsequently amortized on a straight-line basis over the life of the lease as a reduction to rent expense.

New Accounting Pronouncements Issued But Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)." ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principle of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. The Company is currently evaluating the potential impact of ASU 2014-09 on the condensed consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern" that describes how an entity's management should assess whether there are conditions and events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Management should consider both quantitative and qualitative factors in making its assessment. The new standard applies to all entities for the first annual period ending after

December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The Company will assess the potential impact of ASU 2014-15 when applicable circumstances are present.

New Accounting Pronouncements Issued and Adopted

In April 2014, the FASB issued ASU 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." ASU 2014-08 changes the definition of a discontinued operation to include only those disposals of components of an entity that represent a strategic shift that has (or will have) a major effect on an entity's operations and financial results. In addition, ASU 2014-08 requires additional disclosures about both discontinued operations and the disposal of an individually significant component of an entity that does not qualify for discontinued operations presentation in the financial statements. The guidance is effective prospectively for fiscal years, and interim periods within those years, beginning after December 15, 2014, with early adoption permitted. We adopted the provisions of ASU 2014-08 on a prospective basis during the first quarter of fiscal year 2015. The adoption of this ASU did not have an impact on our condensed consolidated financial statements.

There are no other recently issued accounting pronouncements that are expected to have a material impact on our financial condition, results of operations or cash flows.

3. ACQUISITIONS

Merger Agreement with Savant Alaska, LLC

On May 8, 2014, we entered into an Agreement and Plan of Merger with Savant Alaska, LLC ("Savant") 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, which will merge with Savant to facilitate the acquisition. 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 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 the Badami Unit to the Endicott Pipeline. Production from the Savant assets was approximately 1,100 bopd gross (600 bopd net) at the time of our announcement of the acquisition.

We expect the transaction to close by December 2014, following regulatory approval, with a May 1, 2014 effective date as defined in the Agreement and Plan of Merger.

Anchor Point Pipeline Purchase

The acquisition of the Anchor Point Pipeline, closed on August 8, 2014 upon receiving approval from the Regulatory Commission of Alaska. Purchase consideration consisted of Series D Preferred Stock with a fair market value of $5,446 on August 8, 2014, which was released from escrow upon closing.

The purchase of the Anchor Point Pipeline has been accounted for under ASC 805, "Business Combinations." Under ASC 805, the Company is required to allocate the purchase price to assets acquired and liabilities assumed based on their fair values at the acquisition date. The estimated fair value of the properties approximates the fair value of consideration, and as a result, no goodwill was recognized. The following table summarizes the consideration paid for the Anchor Point Pipeline and the allocation of the purchase price to the assets acquired and liabilities assumed that have been included in the Company's condensed consolidated financial statements. The Company is in the process of finalizing the evaluation of the assigned fair values to the assets acquired and liabilities assumed.

Purchase Price:	
Series D Preferred Stock	$5,446
Preliminary Allocation of Assets Acquired and Liabilities Assumed:	
Natural gas pipeline and pipeline support assets	$5,687
Asset retirement obligation	$(241)
Fair value of assets acquired and liabilities assumed	$5,446

7

Table of Contents

In conjunction with the Anchor Point Pipeline, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involved the estimated replacement costs of the pipeline and obsolescence. Assumptions were also made regarding the retirement obligation. With respect to the fair value, these assumptions are considered Level 3 inputs.
Acquisition related costs included legal and other professional services charges.

4. MAJOR CUSTOMERS AND CONCENTRATIONS OF CREDIT RISK

For the three ended October 31, 2014, two customers accounted for 83% and 15% of our consolidated total revenues. For the six months ended October 31, 2014, two customers accounted for 82% and 14% of our consolidated total revenues. Two customers accounted for 11% and 19% of our consolidated accounts receivable as of October 31, 2014. Two customers accounted for 5% and 23% of our consolidated accounts receivable as of April 30, 2014.
Credit is extended to customers based on an evaluation of their creditworthiness and collateral is generally not required. We experienced no credit losses of significance during the three and six months ended October 31, 2014 or 2013.
We maintain our cash and cash equivalents (including restricted cash), which at times may exceed federally insured amounts, in highly rated financial institutions. As of October 31, 2014, we held $14,217 in excess of the $250 limit insured by the Federal Deposit Insurance Corporation.
We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. We attempt to minimize credit-risk exposure to derivative counterparties through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by creditworthy parties. We also enter into master netting agreements to mitigate counterparty performance and credit risk. During the three and six months ended October 31, 2014 and 2013, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

5. RELATED PARTY TRANSACTIONS

We use a number of contract labor companies to provide on demand transportation and labor at our Alaska operations. H&H Industrial, Inc. ("H&H Industrial") is an entity contracted by CIE, a wholly-owned subsidiary of the Company, to provide services related to the exploration and production of oil and natural gas. H&H Industrial is owned by the sister and father of David Hall, who is Chief Operating Officer ("COO") of the Company. For the three and six months ended October 31, 2014, we recorded capital and lease operating expenses related to H&H Industrial of $985 and $1,703, respectively. The Audit Committee of our Board of Directors determined that the amounts paid by us for the services performed were fair and in the best interest of the Company.
On December 9, 2014, the Company entered into a two-year consulting agreement with Deloy Miller under which he agreed to assist us with oil and gas related matters, including assisting with our strategic planning, providing management with drilling advice, and other consulting services we may reasonably request. As compensation for these services, the Company agreed to pay Mr. Miller $275 per year and granted Mr. Miller an option to purchase 100,000 shares of our common stock at an exercise price of $1.35 per share vesting in equal installments on the first and second anniversary of the date that the parties entered into the consulting agreement. Mr. Miller is a related party

to the Company as a result of his former employment with the Company and his relationship to Mr. Boruff, the Company's Executive Chairman, as his former father-in-law. The audit committee of our Board of Directors determined that the consideration given by us for the services to be performed was fair and in the best interest of the Company.

(Dollars in thousands, except per share data and per unit data)

6. OIL AND GAS PROPERTIES AND EQUIPMENT

Oil and gas properties (successful efforts method) are summarized as follows:

	October 31, 2014	April 30, 2014
Property costs:		
Proved property	$479,911	$467,740
Unproved property	93,498	243,230
Total property costs	573,409	710,970
Less: Accumulated depletion	(210,854)	(66,143)
Oil and gas properties, net	$362,555	$644,827

On October 31, 2014, the significant decline in crude oil prices during the second quarter of fiscal 2015 was identified as an impairment related triggering event for proved and unproved properties. The Redoubt Unit failed the step 1 test which is based on undiscounted cash flows. The failure of step 1 required the Company to measure the estimated fair value of the Redoubt Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved and unproved properties of $112,414 and $152,887, respectively. The factors used to estimate the fair value of the Redoubt Unit include, but are not limited to, estimates of reserve quantities, future commodity prices, the timing of future production, operating costs, capital expenditures and a risk adjusted discount rate. Because these significant fair value inputs are typically not observable, we have categorized the amounts as Level 3 inputs. As of October 31, 2014, the proved and unproved properties of the Redoubt Unit were written down to their estimated fair value of $122,587.
On October 31, 2014, the Company recorded a charge to exploration expense of $13,325 for Olsen Creek #2, which was determined to be a dry hole. In addition, on October 31, 2014, we recognized an impairment of $1,319 to write down the net assets of substantially all of our Tennessee oil and gas properties to reflect the expected sales price. These properties were sold on November 20, 2014.
Equipment is summarized as follows:

	October 31, 2014	April 30, 2014
Machinery and equipment	$5,997	$7,759
Vehicles	512	1,877
Buildings	2,447	2,726
Office equipment	1,180	1,108
Leasehold improvements	677	527
Drilling rigs	43,640	30,210
Capital lease asset	3,678	1,500
Natural gas pipeline and pipeline support assets	5,687	—
	63,818	45,707
Less: Accumulated depreciation	(9,588)	(10,338)
Equipment, net	$54,230	$35,369

The Company classified its aircraft as an asset held for sale on our condensed consolidated balance sheets as of April 30, 2014 and October 31, 2014. The aircraft is recorded at estimated fair value less cost to sell. Proceeds received from the sale of the aircraft are required to pay down the Company's Second Lien Credit Facility (defined below).

During the three months ended October 31, 2014, a substantial portion of our Tennessee assets were reclassified and presented as assets held for sale. The Company estimates the fair value of the assets and liabilities to be $5,072 and $1,495, respectively. The cost to sell the assets, including commissions and legal costs, are estimated to be $246. An impairment charge of $1,319 was recorded, representative of the excess of the assets carrying value over the estimated fair value less cost to sell. Because these significant fair value inputs are typically not observable, we have categorized the amounts as Level 3 inputs.

(Dollars in thousands, except per share data and per unit data)

Depreciation, depletion and amortization consisted of the following:

	For the Six Months Ended October 31,	
	2014	2013
Depletion of oil and gas related assets	$35,026	$12,532
Depreciation and amortization of equipment	2,034	2,178
Total	$37,060	$14,710

We have obtained multiple reserve reports in the last twelve months due to our acquisition and drilling activity in Alaska. The reserve reports have provided incremental information to allow us to better understand the reserves on a field basis. These changes in reserve estimates have caused an increase in proved property depletion.

Entry into Glacier Rig Purchase Option

Effective as of July 4, 2014, we entered into a Purchase and Sale Agreement with Teras Oilfield Support Limited which grants us the right to purchase the Glacier Drilling Rig #1, a Mesa 1000 carrier-mounted land drilling rig, which we have renamed Rig 37 and related equipment. During the six months ended October 31, 2014, the Company paid $6,346 in connection with the acquisition of Rig 37 and has an obligation to pay an additional $654 upon the occurrence of certain conditions.

Acquisition of Rig 36 and Related Capital Lease

On May 5, 2014, we entered into a Rig Equipment Purchase Agreement with Baker Process, Inc. to purchase a 2400 HP rig, which we have named Rig 36, and related equipment. On May 9, 2014, the Company entered into a capital lease with First National Capital, LLC to finance the purchase of and planned future modifications to Rig 36. We have drawn $3,250 under the capital lease.

7. DERIVATIVE INSTRUMENTS

Derivative Instruments

Commodity Derivatives

From time to time, we enter into derivative financial instruments to mitigate our exposure to crude oil price volatility. The derivative financial instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of over-the-counter variable-to-fixed price commodity swaps. All derivative financial instruments are recognized in our condensed consolidated financial statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. We do not use hedge accounting for commodity derivatives; thus, the open positions are recorded at fair value with the change in value recorded to earnings.

We have experienced and could continue to earnings volatility due to fluctuations in the fair value of these commodity derivative contracts. The lack of hedge accounting has no impact on our reported cash flows, although our results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in crude oil prices. These fluctuations could be significant in a volatile pricing environment.

As of October 31, 2014, we had the following open crude oil derivative positions. All are priced based on the Brent crude oil futures as traded on the Intercontinental Exchange.

Fixed - Price Swaps

Production Period ending April 30,	Bbls	Weighted Average Fixed Price
2015	389,600	98.71
2016	787,600	95.36
2017	232,600	93.97

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

Derivative Activities Reflected on Condensed Consolidated Balance Sheets
The following table presents the fair value of commodity derivatives. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

	Asset Derivatives				Liability Derivatives			
	October 31, 2014		April 30, 2014		October 31, 2014		April 30, 2014	
Derivatives not designated as hedging instruments under ASC 815	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity derivatives	Prepaid expenses and other	$7,222	Prepaid expenses and other	$88	Current portion of derivative instruments	$—	Current portion of derivative instruments	$(3,315)
Commodity derivatives	Other assets	2,159	Other assets	26	Long-term portion of derivative instruments	—	Long-term portion of derivative instruments	(4,006)
Total derivatives not designated as hedging instruments under ASC 815		$9,381		$114		$—		$(7,321)

Offsetting of Derivative Assets and Liabilities
The following table presents our gross and net derivative assets and liabilities:

	Gross Amount Presented on Balance Sheet	Netting Adjustments [(a)]	Net Amount
October 31, 2014			
Derivative assets with right of offset or master netting agreements	$9,381	$—	$9,381
April 30, 2014			
Derivative assets with right of offset or master netting agreements	$114	$(114)	$—
Derivative liabilities with right of offset or master netting agreements	$(7,321)	$114	$(7,207)

(a) The Company has an agreement in place that allows for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of default under the agreement.

Derivative Activities Reflected on Condensed Consolidated Statements of Operations

Gains and losses on derivatives are reported in the condensed consolidated statements of operations. The following represents the Company's reported gains and losses on derivative instruments for the periods presented:

	For the Three Months Ended October 31,		For the Six Months Ended October 31,	
	2014	2013	2014	2013
Gain (loss) on derivatives, net	$23,089	$(4,190)	$16,186	$(7,266)

As of October 31, 2014, we did not maintain any derivative instruments that were classified as fair value hedges or trading securities. In addition, as of October 31, 2014, we did not maintain any derivative instruments containing credit risk contingencies.

(Dollars in thousands, except per share data and per unit data)

8. FAIR VALUE MEASUREMENTS

Fair Value Measurement on a Recurring Basis

The carrying amounts reported in the condensed consolidated balance sheets for cash and cash equivalents, trade receivables, account payables and other short-term liabilities approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments. Other fair value measurements are noted throughout the Notes to the Condensed Consolidated Financial Statements and the level of inputs classified. The fair values of the Company's commodity derivative instruments are classified as Level 2 measurements as they are calculated using industry standard models using assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, and discount factors. The following summarizes the fair value of the Company's commodity derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated:

	Fair Value Measurements		
At October 31, 2014	Level 1	Level 2	Level 3
Commodity derivative asset	$—	$9,381	$—
Total	$—	$9,381	$—
At April 30, 2014			
Commodity derivative asset	$—	$114	$—
Commodity derivative liability	—	(7,321)	—
Total	$—	$(7,207)	$—

There were no transfers between Level 1, Level 2 or Level 3 during the six months ended October 31, 2014.

9. DEBT

As of October 31, 2014 and April 30, 2014, we had the following debt obligations:

	October 31, 2014	April 30, 2014
Second Lien Credit Facility	$175,000	$175,000
Debt discount related to Second Lien Credit Facility	(2,858)	(3,296)
First Lien RBL	36,000	—
Gunsight Promissory Note payable	950	950
Apollo prepayment and extension fee note payable	4,612	9,223
Capital lease obligation	2,951	—
Series B Preferred Stock	2,363	2,325
Total debt obligations	219,018	184,202
Less: Current maturities	(6,095)	(9,459)
Total debt less current maturities	$212,923	$174,743

Second Lien Credit Facility

On February 3, 2014, we refinanced our $100,000 credit facility with Apollo Investment Corp. ("Apollo") (the "Prior Credit Facility") by entering into a new Credit Agreement (the "Second Lien Credit Agreement") with Apollo and certain affiliates of Highbridge Capital Strategies (the "Second Lien Lenders") which set forth the terms of a credit facility of up to $175,000 (the "Second Lien Credit Facility").

The Second Lien Credit Agreement provides for a $175,000 term credit facility, all of which was made available to and drawn by us on the closing date. The amounts drawn were subject to a 2% original issue discount. Absent an event of default, amounts outstanding under the Second Lien Credit Facility bear interest at a rate of LIBOR plus 9.75%, subject to a 2% LIBOR floor. The Second Lien Credit Facility permitted us to enter into a reserve-based revolving credit facility of up to $100,000 on

Table of Contents

certain agreed terms which would be secured on a first-lien basis. Upon entering into such revolving credit facility and a related intercreditor agreement, the Second Lien Credit Facility would become a second-lien credit facility. We entered into a credit agreement for a revolving credit facility (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") on June 2, 2014. The First Lien Loan Agreement provides for a $250,000 senior secured, reserve-based revolving credit facility (the "First Lien RBL"). In connection with our entry into the First Lien Loan Agreement, we amended the Second Lien Credit Agreement. The Second Lien Credit Facility carries a four year maturity. The Second Lien Credit Facility contains covenants, including but not limited to, a leverage ratio, interest coverage ratio, current ratio, asset coverage ratio, minimum gross production and change of management control covenants, as well as other covenants customary for a transaction of this type. As of October 31, 2014, there was an event of default under the Second Lien Credit Facility arising from Mr. Scott M. Boruff stepping down as chief executive officer of the Company (the "Second Lien Technical Default"). Additionally, we were not in compliance with certain of the required financial covenants as of October 31, 2014 (the "Second Lien Covenant Default"), although we were in compliance with the production and other covenants. The Second Lien Technical Default and Second Lien Covenant Default were waived or otherwise remedied by the December 2014 Second Lien Amendment, as described below in Note 16, Subsequent Events.
We used $75,306 of the proceeds drawn under the Second Lien Credit Facility to refinance the Prior Credit Facility with Apollo and $56,577 to finance the acquisition of the North Fork unit. In addition, $3,071 was used to retire the obligations owed under the MEI Loan Documents. The remainder of the proceeds from the Second Credit Facility were used for general corporate purposes. The fair value of the outstanding balance of the Second Lien Credit Facility was $171,781 and $176,785 as of October 31, 2014 and April 30, 2014, respectively, as calculated using the discounted cash flows method. Level 3 inputs were used to calculate the fair value of the outstanding balance of the Second Lien Credit Facility.
On the closing date, in connection with the Second Lien Credit Facility, we, along with all of our consolidated subsidiaries (other than MEI), entered into an Amended and Restated Guarantee and Collateral Agreement (the "Second Lien Guarantee") with Apollo, for the benefit of the lenders from time to time party to the Second Lien Credit Agreement. Under the terms of the Second Lien Guarantee and related security documents, each of our consolidated subsidiaries (other than MEI) have guaranteed our obligations under the Second Lien Credit Facility and we and those subsidiaries have granted a security interest in substantially all of their assets to secure the performance of the obligations arising 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. 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.
We entered into Amendment No. 2 to the Second Lien Credit Agreement, which amended a default provision to remove its reference to David Voyticky, our former president. Prior to this amendment, under the Second Lien Credit Agreement, the resignation of Mr. Voyticky would have been a default. In addition, this amendment removed references to Mr. Voyticky from certain defined terms used in the Second Lien Credit Agreement.
We entered into Amendment No. 3 to the Second Lien Credit Agreement, dated as of August 19, 2014, to the Second Lien Credit Agreement, which (1) increased the total amount of obligations we may enter into under capital leases from time to time, (2) allowed us to make certain investments in Savant, and (3) increased the amount of preferred stock that we may issue, among other things.
First Lien RBL

On June 2, 2014, we entered into the First Lien Loan Agreement, among the Company, as borrower, KeyBank, as the RBL Administrative Agent, and 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, $60,000 of which was made available to us on the closing date. The borrowing base will be redetermined semi-annually on February 1st and August 1st of each year. 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 (per the table below).

Table of Contents

MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

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 expire on the third anniversary of its closing. It contains customary covenants, including, but not limited to, a leverage, interest coverage, current ratio, minimum gross production, minimum liquidity, asset coverage and change of management control covenants. Due to the existence of the Second Lien Technical Default which arose when Scott M. Boruff stepped down as chief executive officer of the Company, as of October 31, 2014, there was an event of default under the First Lien Loan Agreement’s cross default provision (the "First Lien Technical Default"). Additionally, we were not in compliance with certain of the required financial covenants as of October 31, 2014 (the "First Lien Covenant Default"), although we were in compliance with the production and other covenants. The First Lien Technical Default and First Lien Covenant Default were waived or otherwise remedied by the December 2014 First Lien Amendment, as described below in Note 16, Subsequent Events.

The Company drew $20,000 on the closing date under the First Lien RBL, which was used to provide working capital for development drilling in Alaska. The amounts available were subject to an upfront fee equal to 1% of the initial borrowing base. On June 20, 2014, we requested an additional $10,000, which was funded on June 24, 2014. We repaid borrowings of $10,000 during the six months ended October 31, 2014, and drew down $16,000 on August 1, 2014. The fair value of floating-rate debt approximates the carrying amount because the interest rates paid are based on short-term maturities.

Also on June 2, 2014, in connection with the First Lien RBL, we, along with all of our consolidated subsidiaries (other than MEI, Miller Energy Colorado 2014-1, LLC, and Miller 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 Energy Colorado 2014-1, LLC, and Miller Drilling 2009-A, L.P.) have guaranteed the obligations under the First Lien RBL. Along with the aforementioned subsidiaries, we have granted a security interest in substantially all of our assets to secure the performance of the obligations arising under the First Lien RBL.

On August 11, 2014, we entered into the First Amendment to our First Lien Loan Agreement, which amended a default provision to remove its reference to Mr. Voyticky. Prior to this amendment, under the First Lien Loan Agreement, the resignation of Mr. Voyticky would have been a default. In addition, this amendment removes references to Mr. Voyticky from certain defined terms used in the First Lien Loan Agreement.

On August 19, 2014, we entered into the Second Amendment to our First Lien Loan Agreement, which (1) increases the total amount of obligations we may enter into under capital leases from time to time, (2) allows us to make certain investments in Savant, and (3) increases the amount of preferred stock that we may issue, among other things.

Series B Preferred Stock

The outstanding Series B Preferred Stock is classified as long-term debt in accordance with ASC 480, "Distinguishing Liabilities from Equity." As of October 31, 2014 and April 30, 2014, the fair value of Series B Preferred Stock was $2,075 and $2,197, respectively, as calculated using the discounted cash flow method. The fair value of the our Series B Preferred Stock is classified as a Level 3 measurement as the fair value is calculated using a discounted cash flow model.

On July 28, 2014, our Board approved a semiannual dividend to shareholders of approximately $6.05 per share on our Series B Preferred Stock, which was paid on the next regularly scheduled divided payment date of September 2, 2014, in accordance with the terms of our charter, as September 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 12% per share, based on the $100.00 per share stated liquidation preference for the Series B Preferred Stock, accruing from March 2014 through August 2014. The record date, as required in accordance with our charter, was August 15, 2014.

Debt Issue Costs

As of October 31, 2014 and April 30, 2014, our unamortized deferred financing costs were $2,385 and $803, respectively, which relates to the First Lien RBL and the Second Lien Credit Facility. These costs are being amortized over the term of the respective debt instruments.

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

10. ASSET RETIREMENT OBLIGATIONS

The following table presents changes to the Company's asset retirement obligation ("ARO") liability for the six months ended October 31, 2014 and 2013:

	2014	2013
Asset retirement obligation, as of April 30,	$22,872	$19,890
Additions, including Anchor Point Pipeline	262	—
Revisions	(99)	—
Accretion expense	697	598
Settlements	(121)	(16)
North Fork properties purchase price adjustment	159	—
Asset retirement obligation, as of October 31,	$23,770	$20,472
Less: Asset retirement obligation related to assets held for sale	(1,494)	—
Revised asset retirement obligation, as of October 31,	$22,276	$20,472

The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.
Any additional retirement obligations will increase the liability associated with new oil and natural gas wells and other facilities. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligations.

11. STOCK-BASED COMPENSATION

During fiscal years 2010 and 2011, our Compensation Committee and Board of Directors adopted share-based compensation plans authorizing 3,000,000 and 8,250,000 shares of common stock under each plan, respectively. On April 16, 2014, the number of shares of common stock available for issuance increased by 5,000,000 shares of common stock under the 2011 Equity Compensation Plan (the "2011 Plan"). The amendment to the 2011 Plan providing for the increase was adopted by our Board of Directors on March 10, 2014, and approved by our shareholders on April 16, 2014. On October 30, 2014, the number of shares of common stock available for issuance increased by 2,500,000 shares of common stock under the 2011 Plan. The amendment to the 2011 Plan providing for the increase was adopted by our Board of Directors on September 14, 2014, and approved by our shareholders on October 30, 2014. The share-based compensation plans allow us to offer our employees, officers, directors and others an opportunity to acquire a proprietary interest in the Company and enable us to attract, retain, motivate and reward such persons in order to promote our success. Each plan authorizes the issuance of incentive stock options, nonqualified stock options and restricted stock. All awards issued under the share-based compensation plans must be approved by our Compensation Committee. At October 31, 2014 and April 30, 2014, there were 59,166 and 2,500 shares available under the 2010 Plan, respectively, and 2,483,423 and 3,132,078 additional shares available under the 2011 Plan, respectively.
Allocated between general and administrative expenses and cost of oil and gas sales within the condensed consolidated statements of operations is stock-based compensation expense for the three and six months ended

October 31, 2014 of approximately $7,414 and $9,059, respectively, and $1,469 and $3,025 for the three and six months ended October 31, 2013, respectively. We also recognized non-employee expense related to warrants issued for the three and six months ended October 31, 2014 of approximately $158 and $574, respectively, and $439 and $549 for the three and six months ended October 31, 2013, respectively.

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

The following table summarizes stock options and warrants activity for the period presented:

	Number of Options and Warrants	Weighted Average Exercise Price
Beginning balance at April 30, 2014	15,021,347	$4.99
Granted	2,670,500	4.59
Exercised	(321,354)	4.44
Cancelled	(386,512)	5.14
Ending balance	16,983,981	4.93
Options and warrants exercisable at October 31, 2014	13,376,916	$4.87

The following table summarizes stock options and warrants outstanding, including exercisable shares at October 31, 2014:

Options and Warrants Outstanding				Options and Warrants Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.01 to $1.82	1,480,200	0.7	$0.70	1,480,200	$0.70
$2.00 to $4.99	3,886,334	7.4	4.04	2,199,769	3.76
$5.15 to $5.53	4,137,447	2.5	5.32	3,641,947	5.33
$5.68 to $5.94	3,535,000	6.1	5.91	3,295,000	5.92
$6.00 to $6.95	3,945,000	3.1	6.13	2,760,000	6.15
	16,983,981	4.3	$4.93	13,376,916	$4.87

The following table summarizes restricted stock activity for the six months ended October 31, 2014:

Unvested at April 30, 2014	465,432
Granted	930,655
Vested	(1,139,754)
Cancelled	(25,000)
Unvested at October 31, 2014	231,333

12. STOCKHOLDERS' EQUITY

Common Stock

At October 31, 2014, we had 46,599,471 shares of common stock outstanding. We issued 842,774 shares during the six months ended October 31, 2014, of which 521,420 shares were issued to employees for compensation, and 321,354 shares were related to the exercise of equity rights.

Series D Preferred Stock

During the three months ended October 31, 2014, we sold 16,120 shares of our 10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock (the "Series D Preferred Stock") pursuant to an "at-the-market" offering, yielding net proceeds of $400.

On August 25, 2014, we completed and closed a public offering of our 10.5% Series D Preferred Stock liquidation preference $25.00 per share. We issued 750,000 shares which were offered to the public at $24.50 per share for gross proceeds of $18,375. We incurred issuance costs of $1,352, yielding net proceeds of $17,023.

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

Dividends Declared on Preferred Stock
The following table summarizes the Series C Preferred Stock and Series D Preferred Stock dividend activity for the six months ended October 31, 2014.

Series	Declaration Date	Dividend per Share	Annualized Percentage Rate		Par Value	Accrual Period	Record Date	Payment Date
C	July 28, 2014	$0.67	10.75	%	$25.00	Jun. 1 - Aug. 31, 2014	August 15, 2014	September 2, 2014
D	July 28, 2014	$0.66	10.5	%	$25.00	Jun. 1 - Aug. 31, 2014	August 15, 2014	September 2, 2014
C	October 29, 2014	$0.67	10.75	%	$25.00	Sept. 1 - Nov. 30, 2014	November 14, 2014	December 1, 2014
D	October 29, 2014	$0.66	10.5	%	$25.00	Sept. 1 - Nov. 30, 2014	November 14, 2014	December 1, 2014

Fair Value Measurements
The estimated fair value of our Series C and Series D Preferred Stock is $71,684 and $47,171 as of October 31, 2014, respectively, and $77,976 and $31,330 as of April 30, 2014, respectively.

13. INCOME TAXES

We have a significant deferred income tax liability related to the excess of the book carrying value of oil and gas properties over their collective income tax bases. This difference will reverse (through lower tax depletion deductions) over the remaining recoverable life of the properties, resulting in future taxable income in excess of income for financial reporting purposes. As an independent producer of domestic oil and gas, we take advantage of certain elective provisions presently in the Internal Revenue Code allowing for expensing of specified intangible drilling and development costs that are typically capitalized for book purposes. This temporary difference also reverses over the remaining life of the properties. As a result of these elections, we presently have U.S. federal and state net operating loss carryovers that are expected to be fully utilized against future taxable income resulting solely from the reversal of the temporary differences between the book carrying value of oil and gas properties and their tax bases. Our provision for income taxes for the second interim reporting period in fiscal 2015 is based on the actual year-to-date effective rate, as this is our best estimate of our annual effective tax rate for the full fiscal year. The computation of the annual effective tax rate includes a forecast of our estimated "ordinary" income (loss), which is our annual income (loss) from operations before tax, excluding unusual or infrequently occurring (or discrete) items. Significant management judgment is required in the projection of ordinary income (loss) in order to determine the estimated annual effective tax rate. The level of income (or loss) projected for fiscal 2015 causes an unusual relationship between income (loss) and income tax expense (benefit), with small changes resulting in: (i) a potential significant impact on the rate and, (ii) potentially unreliable estimates. As a result, we computed the provision for income taxes for the three and six month periods ended October 31, 2014 and October 31, 2013 by applying the actual effective tax rate to the year-to-date income (loss), as permitted by GAAP. The effective tax rate for the year-to-date period ended October 31, 2014 is a benefit of (41%). The principal differences in our effective tax rate (benefit) for this period and the federal statutory rate of 35% are state income taxes, change in state and local income taxes net of federal benefit and a valuation allowance against our Tennessee net operating loss carry-forwards and credits. No other valuation allowances were deemed necessary in order to fully benefit the Company's year-to-date loss due to the presence of sufficient future taxable income related to the excess of book carrying value in oil and gas properties over their corresponding tax bases. No other sources of taxable income were considered by Management in reaching this conclusion. No significant cash payments of income taxes were made during the year-to-date period ended October 31, 2014, and no significant payments are expected during the succeeding 12 months.

14. ALASKA PRODUCTION CREDITS

Upon qualifying, the Company can apply for several credits under Alaska Statutes 43.55.023 and 43.55.025:

- 43.55.023(a)(1) Qualified capital expenditure credit (20%)
- 43.55.023(l)(1) Well lease expenditure credit (effective June 30, 2010) (40%)
- 43.55.023(a)(2) Qualified capital exploration expenditure credit (20%)
- 43.55.023(l)(2) Well lease exploration expenditure credit (effective June 30, 2010) (40%)
- 43.55.023(b) Carried-forward annual loss credit (25%)
- 43.55.025 Seismic exploration credits (40%)

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Unaudited)
(Dollars in thousands, except per share data and per unit data)

We recognize a receivable when the amount of the credit is reasonably estimable and receipt is probable. For expenditure and exploration based credits, which we receive in the ordinary course of business, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, which we receive in the ordinary course of business, the credit is recorded as a reduction to the Alaska production tax. We did not incur any Alaska production taxes in fiscal 2014, 2013 or 2012, and accordingly, the carried-forward annual loss credits are presented separately in our operating expenses on the condensed consolidated statements of operations.

Balance, April 30, 2014	$49,121
Alaska carried-forward annual loss credits, net [1]	2,732
Applications for expenditure and exploration based credits [1]	41,843
Cash collections for expenditure and exploration based credits	(56,012)
Balance, October 31, 2014	$37,684

[1] Applications for carried-forward annual loss credits and for expenditure and exploration based credits are recorded net of established reserves and also include revisions to prior period applications, if applicable.

During the six months ended October 31, 2014, we recorded net carried-forward annual loss credits of $2,732. We have reduced the basis of capitalized assets by a cumulative total of $84,770 for expenditure and exploration credits. The reductions are recorded on our condensed consolidated balance sheets in oil and gas properties and equipment. As of October 31, 2014 and April 30, 2014, we had outstanding net receivables from the State of Alaska in the amount of $37,684 and $49,121, respectively.

15. LITIGATION

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 May 29, 2014, the court put down a new scheduling order setting forth certain pre-trial deadlines with the final pre-trial conference being set for October 30, 2014. On June 5, 2014, the court entered an order denying the motion to intervene. On November 13, 2014, the court entered an order setting the trial date for this matter on January 20, 2015. 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, David Voyticky, 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. Our final settlement is pending court approval, with an approval hearing set for February 3, 2015.

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, which, as disclosed in the Company's prior periodic reports, was ultimately dismissed in our 2014 fiscal year. The Plaintiff had agreed to voluntarily dismiss the Valdez 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 Valdez 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 did. 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. This case has been dismissed and there is no further action required.

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, and have since returned, 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 were required of us in connection with this settlement, although we did pay the transportation costs of the equipment being returned. As a result, we recorded a gain of $113 related to this settlement in other income (expense), net in our condensed consolidated statement of operations for the six months ended October 31, 2014. As this matter has been resolved, no further action is required.

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 the implied warranty of merchantability, breach of the 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 condensed consolidated balance sheet.

On February 7, 2014, we were served with a lawsuit filed by Vulcan Capital Corporation ("Vulcan") 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 Vulcan had with PlainsCapital Bank wherein Vulcan 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 Vulcan's default of the loan agreement, PlainsCapital Bank 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, but the case was transferred to Texas. We filed a motion to dismiss the case against the Company on October 9, 2014, and we are currently awaiting a ruling on the motion. 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.

16. SUBSEQUENT EVENTS

Divestiture of Tennessee Assets

On November 20, 2014, we closed the previously announced sale of substantially all of our Tennessee oil and gas assets for a purchase price of approximately $3,250 in cash. We also liquidated substantially all of our remaining oil and gas inventory in that State, yielding approximately $600 in net cash proceeds in addition to the purchase price.

Payment of Dividends

The following table summarizes the Series C Preferred Stock and Series D Preferred Stock dividend activity subsequent to October 31, 2014.

Series	Declaration Date	Dividend Paid per Share	Annualized Percentage Rate		Par Value	Accrual Period	Record Date	Payment Date
C	October 29, 2014	$0.67	10.75	%	$25.00	Sept. 1 - Nov. 30, 2014	November 14, 2014	December 1, 2014
D	October 29, 2014	$0.66	10.5	%	$25.00	Sept. 1 - Nov. 30, 2014	November 14, 2014	December 1, 2014

First Lien RBL Amendment

On December 10, 2014, our company (the “Company”) entered into a Third Amendment (the "First Lien Amendment") to our Credit Agreement, dated as of June 2, 2014 (the “First Lien Credit Agreement”), among our Company, as borrower, KeyBank National Association, as administrative agent (the “First Lien Agent”), and the lenders party thereto (the “First Lien Lenders”) and to our Guarantee and Collateral Agreement, dated as of June 2, 2014 among our Company and its subsidiaries and the First Lien Agent. The First Lien Amendment, among other things, (1) amends our leverage and interest covenants, (2) establishes approved plans of development (“Plans”) and defines “Permitted Capital Expenditures” and adds requirements for the development of the our drilling program within those Plans and restricts our ability to engage in capital expenditures other than Permitted Capital Expenditures, (3) permits us to issue an additional $25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of $50,000 in stated liquidation preference in total), (4) adjusts the percentage by value of our oil and gas properties that must be the subject of mortgages in favor of the First Lien Agent (for the benefit of the First Lien Lenders) from 80% to 90%, (5) includes Mr. Carl F. Giesler, Jr., our Chief Executive Officer, as one of the officers designated in the definition of “Change of Control,” (6) eliminates restrictions on the sale of equity interests by Mr. Deloy Miller without impacting that “Change of Control” definition, (7) provides waivers related to certain events of default which arose as a result of Mr. Scott M. Boruff’s resignation as our Chief Executive Officer and certain sales of equity interests by Mr. Boruff as well as in connection with the scheduled payment of dividends on our preferred stock that occurred while an event of default had occurred, (8) extends the date by which the Company must remediate the material weakness in its internal controls over financial reporting from April 30, 2015 to April 30, 2016, but requires an additional borrowing base redetermination, unless waived by the majority of the First Lien Lenders, in the event our April 30, 2015 audited financial statements are issued with any qualification as to the effectiveness of our internal controls over financial reporting, (9) makes certain technical amendments intended to allow us to close the acquisition of Savant by easing certain requirements (which would have applied after that acquisition in the absence of this First Lien Amendment) related to its subsidiary, Nutaaq Pipeline, LLC, (10) requires that we not permit the aggregate revolving credit exposure of the First Lien Lenders to exceed $50,000 in the aggregate prior to next redetermination date for our borrowing base, scheduled for February 1, 2015 and (11) requires that the next receipt of tax credits by our Company be used as a prepayment of the outstanding loans under the First Lien Credit Agreement; provided that we receive that payment before the next scheduled redeterminaton date of our borrowing base, we agree not to permit the aggregate revolving credit exposure of the First Lien Lenders to exceed $40,000 in the aggregate.

Second Lien Amendment

On December 10, 2014, we entered into Waiver and Amendment No. 4 to Credit Agreement and Amendment No. 2 to Guarantee and Collateral Agreement (the “Second Lien Amendment”) to our Credit Agreement, dated as of February 3, 2014 (the “Second Lien Credit Agreement”), among our Company, as borrower, Apollo Investment Corporation, as administrative agent (the “Second Lien Agent”), and the lenders party thereto (the “Second Lien Lenders”) and our Guarantee and Collateral Agreement, dated as of February 3, 2014 among our Company and its subsidiaries and the Second Lien Agent. The Second Lien Amendment, among other things, (1) makes conforming amendments to our leverage and interest covenants, matching those in the First Lien Amendment, (2) establishes the Plans and defines “Permitted Capital Expenditures” in the same manner as the First Lien Amendment, and adds substantially similar requirements in connection with our development of the our drilling program within those Plans and substantially similar restrictions on our ability to engage in capital expenditures other than Permitted Capital Expenditures, (3) permits us to issue an additional $25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (as with the First Lien Amendment, to a total of $50,000 in stated liquidation preference in total), (4) adjusts the percentage by value of our oil and gas properties that must be the subject of mortgages in favor of the Second Lien Agent (for the benefit of the Second Lien Lenders) from 80% to 90%, (5) includes Mr. Carl F. Giesler, Jr., our Chief Executive Officer, as one of the officers designated in the definition of “Change of Control” under the Second Lien Credit Agreement, (6) eliminates restrictions on the sale of equity interests by Mr. Deloy Miller without impacting the “Change of Control” definition therein, (7) provides waivers related to certain events of default which arose as a result of Mr. Scott M. Boruff’s resignation as our Chief Executive Officer and certain sales of equity interests by Mr. Boruff as well as in connection with a scheduled payment of dividends on our preferred stock that occurred while an event of default had occurred; (8) extends the date by which the Company must remediate the material weakness in its internal controls over financial reporting from April 30, 2015 to April 30, 2016, (9) waives the requirement that the proceeds of the sale of (i) certain miscellaneous oil and gas equipment and office supplies in Tennessee or (ii) interests in the oil and gas properties of Savant, be applied to prepay the loans under the Second Lien Credit Agreement, so long as those proceeds are applied to certain projects specified in the Plans, (10) makes certain technical amendments intended to allow us to close the acquisition of Savant by easing certain requirements (which would have applied after that acquisition in the absence of this Second Lien Amendment) related to its subsidiary, Nutaaq Pipeline, LLC, (11) increases the interest rate applicable to loans under the Second Lien Credit Agreement by 1% per annum (or, if we elect to pay such interest in kind, by 2% per annum) until our Company has raised $20,000 in net proceeds from the issuance of equity interests of the Company, provided that if we have not raised such amounts within four months, the change in the interest rate becomes permanent and (12) adds additional Events of Default (as defined in the Second Lien Credit Agreement).

Table of Contents

Savant

On May 8, 2014, we entered into an Agreement and Plan of Merger 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 addition to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located on the North Slope. We expect the transaction to close by December 2014, following regulatory approval. There is the potential that we may need to raise more capital through debt or equity to improve our liquidity to finance the merger.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

FORWARD LOOKING STATEMENTS

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, and our Annual Report on Form 10-K, as amended, 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.
See the discussion in the "Risk Factors" and "Caution Concerning Forward-Looking Statements" sections of the Company's Annual Report on Form 10-K filed with the SEC on July 14, 2014, and amended on July 15, 2014. All written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in the section entitled "Risk Factors" included in such Annual Report as well as other cautionary statements that are made from time to time in our other SEC filings and public communications. You should evaluate all forward-looking statements made in this report in the context of these risks and uncertainties.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

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

Executive Overview

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration, development and operation of oil and gas wells in 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 on the North Slope through acquiring the Badami field and pipeline system.
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. 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.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

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 have the ability to raise funds from the sales of our Series C Preferred Stock and Series D Preferred Stock, including "at-the-market" public offerings to support our capital expenditures during our second quarter of fiscal 2015. For the six-month period ended October 31, 2014, we reported notable achievements in several key areas. Highlights for the period include:

- On May 8, 2014, we entered into an Agreement and Plan of Merger 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 addition to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located on the North Slope. We expect the transaction to close by the end of December 2014, following regulatory approval. There is the potential that we may need to raise more capital through debt or equity to improve our liquidity to finance the Savant acquisition.
- 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 7, 2014, we successfully brought online WMRU-2B, an onshore oil well in our West McArthur River Unit field.
- 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.
- On July 4, 2014, we entered into a Purchase and Sale Agreement for the right to purchase Rig 37 and related equipment. An initial payment of $700 was made in connection with the execution and delivery of the agreement. On August 8, 2014, an additional payment of $5,646 was made in connection with the closing of the purchase of Rig 37 and $654 was held in escrow pending the resolution by the seller of a claim related to the rig. Rig 37 is a Mesa 1000 carrier-mounted land-drilling rig that has been mobilized to the North Fork unit. We are presently using Rig 37 to drill NFU 24-26.
- On August 11, 2014, we announced that we were named the successful bidder for an exploration license consisting of 168,581 acres located on the Iniskin Peninsula. We have committed to spend $1,501 over the next four years to explore the acreage, which includes a work commitment bond of $375.
- On August 21, 2014, we announced the receipt of a tax credit certificate from the State of Alaska in the amount of approximately $31,200.
- On August 25, 2014, we completed and closed a public offering of its Series D Preferred Stock. The Company issued 750,000 shares which were offered to the public at $24.50 per share for gross proceeds of $18,375. We incurred issuance costs of $1,352, yielding net proceeds of $17,023.
- On September 14, 2014, our Board of Directors appointed Carl F. Giesler, Jr. as our Chief Executive Officer. In addition, the Board of Directors appointed Scott M. Boruff, our previous Chief Executive Officer, to be the Executive Chairman of the Board.

- On October 28, 2014, our Board of Directors appointed Jeffrey R. McInturff as our Chief Accounting Officer and Acting Chief Financial Officer.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

- On October 30, 2014, we held our annual meeting of shareholders at which Scott M. Boruff, Carl F. Giesler, Jr., Bob G. Gower, Gerald E. Hannahs, Jr., William B. Richardson, A. Haag Sherman, and Charles M. Stivers were elected to our Board of Directors. The Board now consists of seven directors, five of whom are independent.
- On October 31, 2014, we recorded a charge to exploration expense of $13,325 for Olsen Creek #2, which was determined to be a dry hole.
- On October 31, 2014, the significant decline in crude oil prices during the second quarter of fiscal 2015 was identified as an impairment related triggering event for proved and unproved properties. The Redoubt Unit failed the step 1 test which is based on undiscounted cash flows. The failure of step 1 required us to measure the estimated fair value of the Redoubt Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved and unproved properties of $112,414 and $152,887, respectively. Continuing crude oil price declines and the results of drilling efforts or changes in reserve estimates could trigger future impairments.
- On November 20, 2014, we closed on the sale of substantially all of our Tennessee oil and gas properties for approximately $3,250 in cash and liquidated our remaining oil and gas inventory in that State, yielding $600 in cash proceeds. Additionally, we recognized an impairment of $1,319 to write down the net assets as of October 31, 2014 to the November 20, 2014 sales price.
- On December 10, 2014, we amended our First Lien Credit Facility and Second Lien Credit Facility to waive certain events of default that existed as of October 31, 2014, among other things. See Note 16, Subsequent Events.

Fiscal 2015 Outlook

As we head into the second half of fiscal 2015, we are shifting our focus to lower-risk drilling projects with immediate production potential. We expect to steadily grow our production and cash flow with gas-focused drilling opportunities at North Fork. Our Rig 37 is currently being used to drill NFU 24-26 at our North Fork unit. Additionally, we will focus on drilling lower-risk sidetracks at RU-7 and we expect to drill two wells during the summer of 2015 at Badami (subject to regulatory approval of the Savant acquisition). There is the potential that we may need to raise more capital through debt or equity to improve our liquidity to finance the Savant acquisition. No assurance can be made regarding the success of these developments and efforts. Our remaining fiscal 2015 capital budget is approximately $45,000. The majority of this budget is expected to be spent on North Fork gas wells, a sidetrack at RU-7 and RU-5 in Alaska. Due to the uncertainty associated with forecasting production, development costs and changes in commodity prices, we closely monitor our cost levels and revise our capital budgets based on changes in forecasted cash flows. This means our plan for capital expenditures may change as a result of anticipated changes in performance. Further, our ability to fully utilize the budget will be dependent on a number of factors including, but not limited to, access to capital, favorable weather and regulatory approval.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Results of Operations

Three Months Ended October 31, 2014 Compared to Three Months Ended October 31, 2013
Revenues

	For the Three Months Ended October 31, 2014	2013	$ Variance	% Variance
Oil sales:				
Cook Inlet	$17,385	$17,767	$(382)	(2)%
Appalachian region	659	639	20	3
Total	$18,044	$18,406	(362)	(2)
Natural gas sales:				
Cook Inlet	$5,695	$197	5,498	2,791
Appalachian region	170	86	84	98
Total	$5,865	$283	5,582	1,972
Other:				
Cook Inlet	$60	$(113)	173	(153)
Appalachian region	207	220	(13)	(6)
Total	$267	$107	160	150
Total revenues	$24,176	$18,796	$5,380	29 %

Net Production

	For the Three Months Ended October 31, 2014	2013	Variance	% Variance
Oil volume - bbls:				
Cook Inlet	201,635	175,473	26,162	15 %
Appalachian region	5,909	5,832	77	1
Total	207,544	181,305	26,239	14
Natural gas volume[1] - mcf:				
Cook Inlet	516,741	44,478	472,263	1,062
Appalachian region	44,458	27,249	17,209	63
Total	561,199	71,727	489,472	682
Total production[2] - boe:				
Cook Inlet	287,759	182,886	104,873	57
Appalachian region	13,319	10,374	2,945	28
Total	301,078	193,260	107,818	56 %

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1 Cook Inlet natural gas volume excludes natural gas produced and used as fuel gas.
2 These figures present 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.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Pricing

	For the Three Months Ended October 31,					
	2014	2013	$ Variance		% Variance	
Average realized oil sales price - per barrel:						
Cook Inlet	$87.24	$102.74	$(15.50	)	(15	)%
Appalachian region	88.45	100.18	(11.73	)	(12	)
Total	$87.28	$102.65	$(15.37	)	(15	)
Average realized natural gas sales price - per mcf:						
Cook Inlet	$6.91	$4.42	$2.49		56	
Appalachian region	3.83	3.11	0.72		23	
Total	$6.75	$3.91	$2.84		73	%

Oil Prices
All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to changes in global supply and demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in the second quarter of 2015 were 15% below the same period last year. For the three months ended October 31, 2014, realized oil prices averaged $87.28 per bbl, compared with $102.65 per bbl for the same period in the prior year.
Natural Gas Prices
Natural gas is subject to price variances based on local supply and demand conditions. Prices received for natural gas in the second quarter of fiscal 2015 increased over the same period last year. For the three months ended October 31, 2014, realized natural gas prices averaged $6.75 per mcf, compared with $3.91 per mcf for the same period in the prior year. The increase in the averaged realized gas prices resulted from natural gas sales at higher realized prices resulting from the higher contractual prices associated with the acquisition of the North Fork properties.
Oil Sales
During the second quarter of fiscal 2015, oil revenues totaled $18,044, which represents a 2% decrease over the same period in the prior year. Oil revenues represented 75% of our second quarter consolidated total revenues. Net barrels sold for the current period were 206,730, which represents a 27,425 bbl, or 15%, increase as compared to the same period last year. The increase in barrels sold was more than offset by a 15% decrease in realized oil prices.
The increase in net barrels sold results from an increase in oil production for the period. Oil production increased 26,239 bbls, or 14%, to 207,544 bbls. The increase was driven by a 26,162 bbl increase in the Cook Inlet region and a 77 bbl increase in the Appalachian region. The production increase in the Cook Inlet region resulted from new wells being brought online, including WMRU-2B and Sword #1 in our West McArthur River Unit field, and RU-5B in our Redoubt Shoals field.

Table of Contents

(Dollars in thousands, except per share data and per unit data)

The difference between barrels sold and 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. Our inventory remained high during the second quarter of fiscal 2015, which significantly reduced the potential revenue that may have resulted from our increased production.

	For the Three Months Ended October 31, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	99,903	11,348	111,251
Addition to inventory - gross production	240,499	5,909	246,408
Reduction to inventory - gross sales	(238,976)	(7,450)	(246,426)
Pipeline adjustments	(1,026)	—	(1,026)
Ending inventory balance	100,400	9,807	110,207
Net change in inventory	497	(1,541)	(1,044)

Natural Gas Sales

During the second quarter of fiscal 2015, natural gas revenues totaled $5,865, which was 1,972% higher than the same period in the prior year. The increase resulted from a combination of a 73% increase in average realized prices and a 682% increase in production, primarily resulting from the higher contractual prices associated with the acquisition of the North Fork properties. Also contributing to the increase are sales of purchased gas for marketing purposes (see Cost of purchased gas sold, below). Natural gas represented 24% of our second quarter consolidated total revenues.

Other

Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling, 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 the second quarters of fiscal 2015 and 2014, other revenues totaled $267 and $107, respectively.

Cost and Expenses

The table below presents a comparison of our expenses for the three months ended October 31, 2014 and 2013:

	For the Three Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Lease operating expense	$8,963	$5,176	$3,787	73 %
Transportation costs	(442)	987	(1,429)	(145)
Cost of purchased gas sold	1,284	—	1,284	N/A
Cost of other revenue	325	304	21	7
General and administrative	17,901	7,145	10,756	151
Alaska carried-forward annual loss credits, net	323	—	323	N/A
Exploration expense	166,812	148	166,664	112,611
Depreciation, depletion and amortization	20,082	9,018	11,064	123
Accretion of asset retirement obligation	351	301	50	17
Impairment of proved properties	113,734	—	113,734	N/A
Total operating expense	$329,333	$23,079	$306,254	1,327 %

N/A = not applicable

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Lease Operating Expense
The table below presents a comparison of our lease operating expense for the three months ended October 31, 2014 and 2013:

	For the Three Months Ended October 31, 2014	2013	$ Variance	% Variance
Lease operating expense	$8,963	$5,176	$3,787	73 %
Net production - boe	301,078	193,260		
Lease operating expense per boe produced	$29.77	$26.78		

Lease operating expense increased $3,787 from fiscal 2014, or 73%. The increased lease operating expense is primarily attributable to increased production and a lower cost of market adjustment to inventory which negatively impacted lease operating expenses by $1,254 for the three months ended October 31, 2014. In addition, 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 first quarter of fiscal 2015, our lease operating expense per boe produced was $29.77 as compared to $26.78 for the first quarter of fiscal 2014. We expect our lease operating expense per boe produced to decline as production increases.

Transportation Costs
Transportation costs decreased $1,429 from fiscal 2014, or 145%, as we received a refund of $1,670 related to transportation costs in connection with the closing of the Anchor Point Pipeline acquisition.

Cost of Purchased Gas Sold
We engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into intrastate pipeline systems. We incurred $1,284 in purchased gas costs during the second quarter of fiscal 2015 and none during the second quarter of fiscal 2014.

Cost of Other Revenue
Our business is primarily focused on exploration and production activities. The cost of other revenue represents the cost of services provided 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.

	For the Three Months Ended October 31, 2014	2013	$ Variance	% Variance
Direct labor	$243	$140	$103	74 %
Equipment	21	36	(15)	(42)
Repairs	54	115	(61)	(53)
Other	7	13	(6)	(46)
Total	$325	$304	$21	7 %

Table of Contents
(Dollars in thousands, except per share data and per unit data)

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 Three Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Stock-based compensation	$7,501	$1,781	$5,720	321 %
Professional fees	4,870	1,991	2,879	145
Salaries	3,460	1,453	2,007	138
Travel	511	533	(22)	(4)
Employee benefits	396	411	(15)	(4)
Other	1,163	976	187	19
Total	$17,901	$7,145	$10,756	151 %

G&A expenses increased $10,756 from fiscal 2014, or 151% from the same period in the prior fiscal year. Salaries increased 138% from the same period in the prior fiscal year primarily due to additions to our engineering and accounting staff, salary increases of our named executive officers, and an increase in bonus accruals. Stock-based compensation increased 321% due to recent grants to directors and key employees.

Exploration Expense
Exploration expense incurred increased $166,664 from fiscal 2014, or 112,611%. Exploration expense consists of abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization and abandonment associated with leases on unproved properties. During the fiscal second quarter, we wrote off exploratory well Olsen Creek #2 resulting in a charge of $13,325 including unproved leasehold costs, net of tax credits, and $152,887 of unproved property costs of the Redoubt Unit.

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

	For the Three Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Depletion:				
Cook Inlet region	$18,632	$7,802	$10,830	139 %
Appalachian region	411	193	218	113
	19,043	7,995	11,048	138
Depreciation:				
Cook Inlet region	884	840	44	5
Appalachian region	155	183	(28)	(15)
	1,039	1,023	16	2
Total DD&A	$20,082	$9,018	$11,064	123 %

The increase in DD&A expense is primarily a result of increased production from the Cook Inlet region and changes in estimated reserve volumes by field.

Accretion of Asset Retirement Obligation
Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Accretion of asset retirement obligations increased 17% to $351 primarily due to additions to asset retirement obligations during fiscal 2014 related to the North Fork properties.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Impairment of Proved Properties
On October 31, 2014, the significant decline in crude oil prices during the second quarter of fiscal 2015 was identified as an impairment related triggering event for proved properties. The Redoubt Unit failed the step 1 test which is based on undiscounted cash flows. The failure of step 1 required us to measure the estimated fair value of the Redoubt Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved properties of $112,414.
In addition, on October 31, 2014, we recognized an impairment of $1,319 to write down the net assets of substantially all of our Tennessee oil and gas properties to reflect the expected sales price. These properties were sold on November 20, 2014.

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

	For the Three Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Interest expense, net	$(3,618)	$(1,363)	$(2,255)	165 %
Gain (loss) on derivatives, net	23,089	(4,190)	27,279	(651)
Other income (expense), net	33	(2)	35	1,750
Total	$19,504	$(5,555)	$25,059	(451)%

Interest Expense, Net
Interest expense, net, increased $2,255 from fiscal 2014, or 165%. The increase in interest expense was driven primarily by an increase in the average debt balance outstanding, slightly offset by lower interest rates on our borrowings.
Gain (Loss) on Derivatives, Net
We have not designated any of our commodity derivative instruments as accounting hedges. As a result, gains and losses on derivatives include both amounts realized from the cash settlements of our derivative positions and amounts from changes in the fair value of open derivative positions in the period of change. We do not engage in speculative trading and utilize commodity derivatives only as a mechanism to lock in future prices for a portion of our expected crude oil production.
We experienced a favorable change of $27,279 during the three months ended October 31, 2014 compared to the three months ended October 31, 2013. Of the total change, $2,272 was due to a favorable change in realized cash settlements related to our derivative positions in the three months ended October 31, 2014 compared to the three months ended October 31, 2013. The remaining amount was due to changes in the fair value of our open derivative positions in each period.
Income Tax Benefit
Income tax benefit increased $112,896 from fiscal 2014, or 2,328%, due to an increase in loss before income taxes. Our effective income tax rate for the second quarter of fiscal 2015 was 41%. This rate differed from the statutory rate primarily due to state income taxes, change in state rate, state and local income taxes net of federal benefit and a valuation allowance against our Tennessee net operating loss carry-forwards and credits.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Results of Operations

Six Months Ended October 31, 2014 Compared to Six Months Ended October 31, 2013
Revenues

	For the Six Months Ended October 31,					
	2014	2013	$ Variance		% Variance	
Oil sales:						
Cook Inlet	$36,140	$29,401	$6,739		23	%
Appalachian region	1,205	1,263	(58	)	(5	)
Total	$37,345	$30,664	6,681		22	
Natural gas sales:						
Cook Inlet	$11,374	$353	11,021		3,122	
Appalachian region	288	200	88		44	
Total	$11,662	$553	11,109		2,009	
Other:						
Cook Inlet	$120	$134	(14	)	(10	)
Appalachian region	428	453	(25	)	(6	)
Total	$548	$587	(39	)	(7	)
Total revenues	$49,555	$31,804	$17,751		56	%

Net Production

	For the Six Months Ended October 31,					
	2014	2013	Variance		% Variance	
Oil volume - bbls:						
Cook Inlet	404,410	283,908	120,502		42	%
Appalachian region	11,955	12,807	(852	)	(7	)
Total	416,365	296,715	119,650		40	
Natural gas volume[1]- mcf:						
Cook Inlet	1,064,328	72,651	991,677		1,365	
Appalachian region	72,754	57,097	15,657		27	
Total	1,137,082	129,748	1,007,334		776	
Total production[2] - boe:						
Cook Inlet	581,798	296,017	285,782		97	
Appalachian region	24,081	22,323	1,758		8	
Total	605,879	318,340	287,539		90	%

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

2 These figures present 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.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Pricing

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Average realized oil sales price - per barrel:				
Cook Inlet	$93.66	$103.85	$(10.19)	(10)%
Appalachian region	92.39	94.10	(1.71)	(2)
Total	$93.62	$103.41	$(9.79)	(9)
Average realized natural gas sales price - per mcf:				
Cook Inlet	$6.91	$4.86	$2.05	42
Appalachian region	3.95	3.45	0.50	14
Total	$6.79	$4.23	$2.56	61 %

Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to changes in global supply and demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in the first six months of 2015 were 9% below the same period last year. For the six months ended October 31, 2014, realized oil prices averaged $93.62 per bbl, compared with $103.41 per bbl for the same period in the prior year.

Natural Gas Prices

Natural gas is subject to price variances based on local supply and demand conditions. Prices received for natural gas in the six months ended October 31, 2014 were higher over the same period last year. For the six months ended October 31, 2014, realized natural gas prices averaged $6.79 per mcf, compared with $4.23 per mcf for the same period in the prior year. The increase in the averaged realized gas prices resulted from natural gas sales at higher realized prices resulting from the higher contractual prices associated with the acquisition of the North Fork properties.

Oil Sales

During the first six months ended of fiscal 2015, oil revenues totaled $37,345, which represents a 22% increase over the same period in the prior year. Oil revenues represented 75% of our six months ended October 31, 2014 consolidated total revenues. Net barrels sold for the current period were 398,905, which represents a 102,372 bbl, or 35%, increase as compared to the same period last year. The increase in barrels sold was partially offset by a 9% decrease in realized oil prices.

The increase in net barrels sold resulted from an increase in oil production for the period. Oil production increased 119,650 bbls, or 40%, to 416,365 bbls. The increase was driven by a 120,502 bbl increase in the Cook Inlet region offset a 852 bbl decrease in the Appalachian region. The production increase in the Cook Inlet region resulted from new wells being brought online, including WMRU-2B and Sword #1 in our West McArthur River Unit field, and RU-5B in our Redoubt Shoals field.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

The difference between barrels sold and 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 the first six months of fiscal 2015, which significantly reduced the potential revenue that may have resulted from our increased oil production during the current period.

	For the Six Months Ended October 31, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	82,495	10,895	93,390
Addition to inventory - gross production	482,014	11,955	493,969
Reduction to inventory - gross sales	(462,704)	(13,043)	(475,747)
Pipeline adjustments	(1,405)	—	(1,405)
Ending inventory balance	100,400	9,807	110,207
Net change in inventory	17,905	(1,088)	16,817

Natural Gas Sales

During the first six months of fiscal 2015, natural gas revenues totaled $11,662, which was 2,009% higher than the same period in the prior year. The increase resulted from a combination of a 61% increase in average realized prices and a 776% increase in production, primarily resulting from the higher contractual prices associated with the acquisition of the North Fork properties. Also contributing to the increase are sales of purchased gas for marketing purposes (see Cost of purchased gas sold, below). Natural gas represented 24% of our six months consolidated total revenues.

Other

Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling, 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 the first six months of fiscal 2015 and 2014, other revenues totaled $548 and $587, respectively.

Cost and Expenses

The table below presents a comparison of our expenses for the six months ended October 31, 2014 and 2013:

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Lease operating expense	$15,589	$10,816	$4,773	44%
Transportation costs	2,542	1,612	930	58
Cost of purchased gas sold	2,256	—	2,256	N/A
Cost of other revenue	665	588	77	13
General and administrative	27,412	13,505	13,907	103
Alaska carried-forward annual loss credits, net	(2,732)	—	(2,732)	N/A
Exploration expense	167,108	434	166,674	38,404
Depreciation, depletion and amortization	37,060	14,710	22,350	152
Accretion of asset retirement obligation	697	598	99	17
Impairment of proved properties	113,734	—	113,734	N/A
Other operating expense, net	4	—	4	N/A

Total operating expense	$364,335	$42,263	$322,072	762	%

N/A = not applicable

34

Table of Contents
(Dollars in thousands, except per share data and per unit data)

Lease Operating Expense
The table below presents a comparison of our lease operating expense for the six months ended October 31, 2014 and 2013:

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Lease operating expense	$15,589	$10,816	$4,773	44 %
Net production - boe	605,879	318,340		
Lease operating expense per boe produced	$25.73	$33.98		

Lease operating expense increased 44% from the first six months of fiscal 2014, or $4,773. The increased lease operating expense is primarily attributable to increased production and a lower of cost of market adjustment to inventory which negatively impacted our lease operating expenses by $1,254 during the first six months of fiscal 2015. 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 six months ended October 31, 2014, our lease operating expense per boe produced was $25.73 as compared to $33.98 for the same period in the prior fiscal year. We expect our lease operating expense per boe produced to continue to decline as production increases.
Transportation Costs
Transportation costs increased $930 from the first six months of fiscal 2014, or 58%, due to increased oil production and increased gas transportation costs. This increase was offset by a refund of $1,670 related to transportation costs in connection with the closing of the Anchor Point Pipeline acquisition.
Cost of Purchased Gas Sold
We engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into intrastate pipeline systems. We incurred $2,256 in purchased gas costs during the first six months of fiscal 2015 and none during the first six months of fiscal 2014.
Cost of Other Revenue
Our business is primarily focused on exploration and production activities. The cost of other revenue represents the cost of services provided 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.

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Direct labor	$457	$307	$150	49 %
Equipment	58	75	(17)	(23)
Repairs	133	186	(53)	(28)
Other	17	20	(3)	(15)
Total	$665	$588	$77	13 %

35

Table of Contents
(Dollars in thousands, except per share data and per unit data)

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 Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Stock-based compensation	$10,066	$3,380	$6,686	198 %
Professional fees	7,229	4,153	3,076	74
Salaries	6,551	2,376	4,175	176
Travel	932	986	(54)	(5)
Employee benefits	685	824	(139)	(17)
Other	1,949	1,786	163	9
Total	$27,412	$13,505	$13,907	103 %

G&A expenses increased $13,907 from the six months ended October 31, 2014, or 103%. Salaries increased 176% from the same period in the prior fiscal year primarily due to additions to our engineering and accounting staff, salary increases of our named executive officers and an increase in bonus accruals. Stock-based compensation increased 198% due to recent grants to directors and key employees.

Exploration Expense
Exploration expense incurred increased $166,674 from the six months ended October 31, 2014, or 38,404%. Exploration expense consists of abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization and abandonment associated with leases on unproved properties. During the first six months of fiscal 2015, we wrote off exploratory well Olsen Creek #2 resulting in a charge of $13,325 including unproved leasehold costs, net of tax credits, and $152,887 of unproved property costs of the Redoubt Unit.

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

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Depletion:				
Cook Inlet region	$34,268	$11,994	$22,274	186 %
Appalachian region	758	538	220	41
	35,026	12,532	22,494	179
Depreciation:				
Cook Inlet region	1,723	1,813	(90)	(5)
Appalachian region	311	365	(54)	(15)
	2,034	2,178	(144)	(7)
Total DD&A	$37,060	$14,710	$22,350	152 %

The increase in DD&A expense is primarily a result of increased production from the Cook Inlet region and changes in estimated reserve volumes by field.

Accretion of Asset Retirement Obligation
Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. Accretion of asset retirement obligations increased 17% to $99 primarily due to additions to asset retirement obligations.

Table of Contents

(Dollars in thousands, except per share data and per unit data)

Impairment of Proved Properties

On October 31, 2014, the significant decline in crude oil prices during the second quarter of fiscal 2015 was identified as an impairment related triggering event for proved properties. The Redoubt Unit failed the step 1 test which is based on undiscounted cash flows. The failure of step 1 required us to measure the estimated fair value of the Redoubt Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved properties of $112,414.

In addition, on October 31, 2014, we recognized an impairment of $1,319 to write down the net assets of substantially all of our Tennessee oil and gas properties to reflect the expected sales price. These properties were sold on November 20, 2014.

Other Income and Expense

The following table shows the components of other income and expense:

	For the Six Months Ended October 31,			
	2014	2013	$ Variance	% Variance
Interest expense, net	$(6,418)	$(3,644)	$(2,774)	76 %
Gain (loss) on derivatives, net	16,186	(7,266)	23,452	(323)
Other income (expense), net	155	(16)	171	1,069
Total	$9,923	$(10,926)	$20,849	(191)%

Interest Expense, Net

Interest expense, net, increased $2,774 during the six months ended October 31, 2014, or 76%. The increase in interest expense was driven primarily by an increase in the average debt balance outstanding, slightly offset by lower interest rates on our borrowings.

Gain (Loss) on Derivatives, Net

We have not designated any of our commodity derivative instruments as accounting hedges. As a result, gains and losses on derivatives include both amounts realized from the cash settlements of our derivative positions and amounts from changes in the fair value of open derivative positions in the period of change. We do not engage in speculative trading and utilize commodity derivatives only as a mechanism to lock in future prices for a portion of our expected crude oil production.

We experienced a favorable change of $23,452 during the six months ended October 31, 2014 compared to the six months ended October 31, 2013. Of the total change, $1,380 was due to a favorable change in realized cash settlements related to our derivative positions in the six months ended October 31, 2014 compared to the six months ended October 31, 2013. The remaining amount was due to changes in the fair value of our open derivative positions in each period.

Income Tax Benefit

Income tax benefit increased $115,626 during the six months ended October 31, 2014, or 1,221%, due to an increase in loss before income taxes. Our effective income tax rate for the first six months of fiscal 2015 was 41%. This rate differed from the statutory rate primarily due to state income taxes, change in state rate, state and local income taxes net of federal benefit and a valuation allowance against our Tennessee net operating loss carry-forwards and credits.

Liquidity and Capital Resources

Our cash flows, both in the short-term and long-term, are impacted by highly volatile oil and natural gas prices and production. Significant deterioration in commodity prices negatively impacts revenues, earnings and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows.

Our long-term cash flows are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. Cash investments are required continuously to fund exploration and development projects and acquisitions, which are necessary to offset the inherent declines in production and proved reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our future liquidity. For a discussion of risk factors related to our business and operations, please refer to the section entitled "Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended April 30, 2014, as amended.

Table of Contents

(Dollars in thousands, except per share data and per unit data)

For the three and six months ended October 31, 2014, we experienced an operating loss. We anticipate that our operating expenses will continue to increase as we fully develop our assets in the Cook Inlet region and make additional acquisitions. Although we expect an increase in revenues from these development activities, we will continue to utilize our cash to fund drilling activities as well as other operating expenses until such time as we are able to significantly increase our revenues above our operating expenses and capital costs.

Current restricted cash balances include amounts held in escrow to secure Company related credit cards. As of October 31, 2014 and April 30, 2014, current restricted cash also includes $565 and $38 of cash temporarily held in an account that is controlled by our lender. Non-current restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, the possible dismantling of our off-shore platform, performance bonds, and general liability bonds.

On February 3, 2014, we refinanced the Prior Credit Facility by entering into the Second Lien Credit Agreement which set forth the terms of the Second Lien Credit Facility. The Second Lien Credit Agreement provided for a $175,000 term credit facility, all of which was made available to and drawn by us on the closing date and was used to refinance the Prior Credit Facility, to close the North Fork properties acquisition and for general corporate purposes. The amounts drawn were subject to a 2% original issue discount. Amounts outstanding under the Second Lien Credit Facility bear interest at a rate of LIBOR plus 9.75%, subject to a 2% LIBOR floor. The Second Lien Credit Facility carries a four year maturity and contains covenants, including but not limited to, a leverage ratio, interest coverage ratio, current ratio, asset coverage ratio, minimum gross production and change of management control covenants as well as other covenants customary for a transaction of this type. The Second Lien Credit Facility permitted us to enter into a reserve-based revolving credit facility in the nature of the First Lien RBL.

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. On July 31, 2014, we repaid $10,000 and drew down $16,000 on August 1, 2014. The remaining availability under the First Lien RBL was $24,000 as of October 31, 2014. As reserves grow, the borrowing base may be adjusted to provide additional capital to fund our development program. 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. The First Lien RBL carries a three-year maturity and contains covenants matching those contained in the Second Lien Credit Agreement.

Additionally, during the six months ended October 31, 2014, we entered into a capital lease for the newly purchased Rig 36, for a total of $3,250.

On August 20, 2014, we entered into an Underwriting Agreement by and between us and MLV, as representative for the underwriters, with respect to the sale by the Company of 750,000 shares of the Company's Series D Preferred Stock through the offering. The Shares were being offered to the public at $24.50 per share, and we raised gross proceeds of $18,375. The offering closed on August 25, 2014.

On December 10, 2014, our company (the “Company”) entered into a Third Amendment (the "First Lien Amendment") to our Credit Agreement, dated as of June 2, 2014 (the “First Lien Credit Agreement”), among our Company, as borrower, KeyBank National Association, as administrative agent (the “First Lien Agent”), and the lenders party thereto (the “First Lien Lenders”) and to our Guarantee and Collateral Agreement, dated as of June 2, 2014 among our Company and its subsidiaries and the First Lien Agent. The First Lien Amendment, among other things, (1) amends our leverage and interest covenants, (2) establishes approved plans of development (“Plans”) and defines “Permitted Capital Expenditures” and adds requirements for the development of the our drilling program within those Plans and restricts our ability to engage in capital expenditures other than Permitted Capital Expenditures, (3) permits us to issue an additional $25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of $50,000 in stated liquidation preference in total), (4) adjusts the percentage by value of our oil and gas properties that must be the subject of mortgages in favor of the First Lien Agent (for the benefit of the First Lien Lenders) from 80% to 90%, (5) includes Mr. Carl F. Giesler, Jr., our Chief Executive Officer, as one of the officers designated in the definition of “Change of Control,” (6) eliminates restrictions on the sale of equity interests by Mr. Deloy Miller without impacting that “Change of Control” definition, (7) provides waivers related to certain events of default which arose as a result of Mr. Scott M. Boruff's resignation as our Chief Executive Officer and certain sales of equity interests by Mr. Boruff as well as in connection with the scheduled payment of dividends on our preferred stock that occurred while an event of default had occurred, (8) extends the date by which the Company must remediate the material weakness in its internal controls over financial reporting from April 30, 2015 to April 30, 2016, but requires an additional borrowing base redetermination, unless waived by the majority of the First Lien Lenders, in the event our April 30, 2015 audited financial statements are issued with any qualification as to the effectiveness of our internal controls over financial reporting, (9) makes certain technical amendments intended to allow us to close the acquisition of Savant by easing certain requirements (which would have applied after that acquisition in the absence of this First Lien Amendment) related to its subsidiary, Nutaaq Pipeline, LLC, (10) requires that we not permit the aggregate revolving credit exposure of the First Lien Lenders to exceed $50,000 in the aggregate prior to next redetermination date for our borrowing base, scheduled for February 1, 2015 and (11) requires that the next receipt of tax credits by our Company be used as a prepayment of the outstanding loans under the First Lien Credit Agreement; provided that we receive that payment before the next scheduled redeterminaton date of our borrowing base, we agree not to permit the aggregate revolving credit exposure of the First Lien Lenders to exceed $40,000 in the aggregate.

On December 10, 2014, we entered into Waiver and Amendment No. 4 to Credit Agreement and Amendment No. 2 to Guarantee and Collateral Agreement (the “Second Lien Amendment”) to our Credit Agreement, dated as of February 3, 2014 (the “Second Lien Credit Agreement”), among our Company, as borrower, Apollo Investment Corporation, as administrative agent (the “Second Lien Agent”), and the lenders party thereto (the “Second Lien Lenders”) and our Guarantee and Collateral Agreement, dated as of February 3, 2014 among our Company and its subsidiaries and the Second Lien Agent. The Second Lien Amendment, among other things, (1) makes conforming amendments to our leverage and interest covenants, matching those in the First Lien Amendment, (2) establishes the Plans and defines “Permitted Capital Expenditures” in the same manner as the First Lien Amendment, and adds substantially similar requirements in connection with our development of the our drilling program within those Plans and substantially similar restrictions on our ability to engage in capital expenditures other than Permitted Capital Expenditures, (3) permits us to issue an additional $25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (as with the First Lien Amendment, to a total of $50,000 in stated liquidation preference in total), (4) adjusts the percentage by value of our oil and gas properties that must be the subject of mortgages in favor of the Second Lien Agent (for the benefit of the Second Lien Lenders) from 80% to 90%, (5) includes Mr. Carl F. Giesler, Jr., our Chief Executive Officer, as one of the officers designated in the definition of “Change of Control” under the Second Lien Credit Agreement, (6) eliminates restrictions on the sale of equity interests by Mr. Deloy Miller without impacting the “Change of Control” definition therein, (7) provides waivers related to certain events of default which arose as a result of Mr. Scott M. Boruff’s resignation as our Chief Executive Officer and certain sales of equity interests by Mr. Boruff as well as in connection with a scheduled payment of dividends on our preferred stock that occurred while an event of default had occurred; (8) extends the date by which the Company must remediate the material weakness in its internal controls over financial reporting from April 30, 2015 to April 30, 2016, (9) waives the requirement that the proceeds of the sale of (i) certain miscellaneous oil and gas equipment and office supplies in Tennessee or (ii) interests in the oil and gas properties of Savant, be applied to prepay the loans under the Second Lien Credit Agreement, so long as those proceeds are applied to certain projects specified in the Plans, (10) makes certain technical amendments intended to allow us to close the acquisition of Savant by easing certain requirements (which would have applied after that acquisition in the absence of this Second Lien Amendment) related to its subsidiary, Nutaaq Pipeline, LLC, (11) increases the interest rate applicable to loans under the Second Lien Credit Agreement by 1% per annum (or, if we elect to pay such interest in kind, by 2% per annum) until our Company has raised $20,000 in net proceeds from the issuance of equity interests of the Company, provided that if we have not raised such amounts within four months, the change in the interest rate becomes permanent and (12) adds additional Events of Default (as defined in the Second Lien Credit Agreement).

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 and Second Lien Credit Facilities, 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.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

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

	For the Six Months Ended October 31,	
	2014	2013
Sources of cash and cash equivalents:		
Net cash provided by operating activities	$25,483	$4,174
Proceeds from borrowings, net of debt acquisition costs	43,924	18,100
Proceeds from capital lease obligations	3,250	—
Proceeds from Alaska expenditure and exploration based credits	36,809	9,668
Exercise of equity rights	1,409	2,283
Issuance of preferred stock, net of issuance costs	18,964	52,650
Release of restricted cash	—	5,027
Other	—	3
	129,839	91,905
Uses of cash and cash equivalents:		
Cash dividends	(5,863)	(3,258)
Capital expenditures for oil and gas properties	(78,215)	(66,171)
Deposits for potential acquisitions	(3,000)	—
Prepayment of drilling costs	—	(2,192)
Purchase of equipment and improvements	(16,359)	(950)
Payments on debt	(14,611)	—
Principal payments on capital lease obligations	(299)	—
Increase in restricted cash	(2,757)	—
	(121,104)	(72,571)
Increase in cash and cash equivalents	$8,735	$19,334

Net Cash Provided by Operating Activities
Our sources of capital and liquidity are partially supplemented by cash flows from operations, both in the short-term and long-term. These cash flows, however, are highly impacted by volatility in oil and natural gas prices. The factors in determining operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, accretion, non-cash compensation, and deferred income tax expense, which affect earnings but do not affect cash flows.
Net cash provided by operating activities for the first six months of fiscal 2015 totaled $25,483, up $21,309 from the same period in fiscal 2014. The increase resulted primarily from an increase in revenue and a favorable shift in the timing of cash receipts and payments to vendors in the ordinary course of business.
Proceeds from First Lien RBL and Other Items
During the first six months of our 2015 fiscal year, borrowings totaled $46,000 under our First Lien RBL, which were offset by a payment of $10,000 on our First Lien RBL. Additionally, we incurred $2,076 in deferred financing costs.
During the first six months of our 2015 fiscal year, increase in restricted cash was $2,757 as compared to a release of restricted cash of $5,027 in the same period last year. The classification of the net change in restricted cash is dependent on whether unrestricted cash is transferred to or from our restricted cash accounts, on a net basis.
During the first six months of fiscal 2015, we paid $5,863 in dividends on our Series B, C, and D Preferred Stock, compared to $3,258 in dividends on our Series B and C Preferred Stock during the first six months of fiscal 2014.
During the first six months of fiscal 2015, we received proceeds of $3,250 under the Rig 36 capital lease. Additionally, we have made payments of $4,611 in total on the prepayment and extension fee owed to Apollo during the first six months of fiscal 2015.

40

Table of Contents
(Dollars in thousands, except per share data and per unit data)

During the first six months of fiscal 2015, we sold 828,424 shares of Series D Preferred Stock, yielding net proceeds of $18,964. During the same period in fiscal 2014, we sold 1,437,300 shares of Series C Preferred Stock, yielding net proceeds of $29,525, and 1,000,000 shares of Series D Preferred Stock, yielding net proceeds of $23,125.

Capital Expenditures and Alaska Production Tax Credits

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

Total spending on capital projects increased significantly from the same period last year. For the six months ending October 31, 2014, cash paid for capital expenditures was $94,574.

During the six months ended October 31, 2014, we collected $36,809 related to our Alaska production tax credits applied for in prior periods.

Liquidity

Cash and Cash Equivalents

As of October 31, 2014, we had $14,484 in cash and cash equivalents.

Debt and Available Credit Facilities

As of October 31, 2014, outstanding debt consisted of $36,000 and $172,142 under our First Lien RBL and Second Lien Credit Facility, respectively, classified as long-term debt on the accompanying condensed consolidated balance sheets. As of October 31, 2014, we had no additional borrowing capacity under our Second Lien Credit Facility.

Non-GAAP Measures

Adjusted Earnings

Adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA") is a significant performance metric used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We define Adjusted EBITDA as net income (loss) before taxes adjusted by:

- interest expense, net;
- depreciation, depletion and amortization;
- impairments of long-lived assets;
- asset disposals;
- accretion of asset retirement obligation;
- non-cash exploration costs;
- stock-based compensation expense;
- non-cash employee bonuses;
- non-recurring litigation settlements and related matters;
- non-recurring severance payments;
- non-recurring North Fork properties gas transportation costs;
- (gain) loss on derivatives, net less cash settlements.

Our Adjusted EBITDA should not be considered as a substitute for net income (loss), operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with

GAAP. Our Adjusted

Table of Contents
(Dollars in thousands, except per share data and per unit data)

EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.
The following tables present a reconciliation of net income (loss) before income taxes to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

	For the Three Months Ended October 31,		For the Six Months Ended October 31,	
	2014	2013	2014	2013
Loss before income taxes	$(285,654)	$(9,838)	$(304,857)	$(21,385)
Adjusted by:				
Interest expense, net	3,619	1,363	6,418	3,644
Depreciation, depletion and amortization	20,082	9,018	37,060	14,710
Impairment of proved properties	113,734	—	113,734	—
Asset disposals	47	—	47	—
Accretion of asset retirement obligation	351	301	697	598
Non-cash exploration costs	166,812	148	167,108	277
Stock-based compensation	7,514	1,908	10,113	3,574
Non-cash employee bonuses	41	—	1,586	—
Non-recurring litigation settlements and related matters	3,364	—	4,738	—
Non-recurring severance payments	1,489	—	1,489	—
Non-recurring North Fork properties gas transportation costs	—	—	1,813	—
Derivative contracts:				
(Gain) loss on derivatives, net	(23,089)	4,190	(16,186)	7,266
Cash settlements (paid) received	1,047	(1,225)	(402)	(1,782)
Adjusted EBITDA	$9,357	$5,865	$23,358	$6,902

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil, gas, and interest rates, or adverse governmental actions. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Price Risk

Our revenues, earnings, cash flow, capital investments, and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil and natural gas, which have historically been very volatile due to unpredictable events such as macro-economic conditions, weather, and political climate.
We periodically enter into commodity derivative contracts to economically hedge a portion of our projected oil production in order to support oil prices at targeted levels and to manage our overall exposure to oil price fluctuations. During the six months ended October 31, 2014, approximately 95% of our crude oil production was economically hedged with derivative contracts. Realized gains or losses from our price-risk management activities are recognized in gain (loss) on derivatives, net when the associated production occurs. We do not hold or issue derivative instruments for trading purposes.
On October 31, 2014, we had open oil derivative instruments in a net asset position with a fair value of $9,381. A 10% increase in oil prices would result in a net liability position with an approximate fair value of $3,155, while a 10%

decrease in prices would result in a net asset position with an approximate fair value of $21,917.

We conduct our risk management activities for commodities under the controls and governance of our risk management policy. The Audit Committee of our Board of Directors approves and oversees these controls, which have been implemented by designated members of the management team. The treasury and accounting departments also provide separate checks and reviews

Table of Contents
(Dollars in thousands, except per share data and per unit data)

on the results of hedging activities. Controls for our commodity risk management activities include limits on volume, segregation of duties, delegation of authority and a number of other policy and procedural controls.
The following tables summarize, for the periods indicated, our hedges currently in place through December 2016. All of these derivatives are accounted for as mark-to-market activities. All of these derivatives are variable-to-fixed price commodity swap contracts which price is based on the Brent crude oil futures as traded on the Intercontinental Exchange.

	For the Quarter Ended (in barrels)									
	July 31,		October 31,		January 31,		April 30,		Total	
Fiscal	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
2015	—	—	—	—	198,200	100.28	191,400	97.09	389,600	98.71
2016	198,200	96.74	197,200	96.36	198,200	95.16	194,000	93.16	787,600	95.36
2017	148,600	93.30	50,000	95.47	34,000	94.68	—	—	232,600	93.97
									1,409,800	$96.06

Interest Rate Risk
We are subject to interest rate risk in connection with our First Lien RBL and our Second Lien Credit Facility. Our principal interest rate exposure relates to our First Lien RBL which is based on LIBOR plus 300 to 400 basis points. Our Second Lien Credit Facility is based on LIBOR plus 9.75%, subject to a 2% LIBOR floor. Given current LIBOR rates, we do not believe LIBOR is likely to exceed the 2% floor. Thus, we believe our interest rate risk is primarily associated with our First Lien RBL.
Customer Credit Risk
We are exposed to the credit risk of our customers. For the six months ended October 31, 2014, 82% of our total consolidated revenues and 11% of our consolidated accounts receivable resulted from one of our oil and gas customers. No significant uncertainties related to the collectability of amounts owed to us exist in regard to this customer.
This customer concentration increases our exposure to credit risk on our receivables, since the financial solvency of this and other customers could have a significant impact on our results of operations. If our customers become financially insolvent, they may not be able to continue to operate or meet their payment obligations. Any material losses as a result of customer defaults could harm and have an adverse effect on our business, financial condition or results of operations. Substantially all of our trade accounts receivable are unsecured.

ITEM 4. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures
Under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and our Interim Chief Financial Officer ("CFO"), we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, at the end of the period covered by this report (the "evaluation date"). In conducting its evaluation, management considered the material weaknesses in our disclosure controls and procedures and internal control over financial reporting described in Item 9A of our Annual Report on Form 10-K for the year ended April 30, 2014 as filed with the SEC on July 14, 2014, and amended on July 15, 2014.
As of the evaluation date, our CEO and CFO have concluded that we did not maintain disclosure controls and procedures that were effective in providing reasonable assurances that information required to be disclosed in our reports filed under the Securities Exchange act of 1934 was recorded, processed, summarized and reported within the time periods prescribed by SEC rules and regulations, and that such information was accumulated and communicated to our management to allow timely decisions regarding required disclosures.

Our management, including the CEO and CFO, does not expect that our disclosure controls and procedures will prevent all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

We are currently working to remediate the material weaknesses identified in our Annual Report on Form 10-K for the year ended April 30, 2014 as filed with the SEC on July 14, 2014, and amended on July 15, 2014. Such efforts have included hiring an additional accounting and finance director and enhancing the business understanding and relevant knowledge possessed by those operating management review controls. We can give no assurance that the measures we have taken will remediate the material weakness that we identified or that any additional material weaknesses will not arise in the future.

Other than the initiatives described above, there have been no changes in our internal control over financial reporting during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

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 May 29, 2014, the court put down a new scheduling order setting forth certain pre-trial deadlines with the final pre-trial conference being set for October 30, 2014. On June 5, 2014, the court entered an order denying the motion to intervene. On November 13, 2014, the court entered an order setting the trial date for this matter on January 20, 2015. 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, David Voyticky, 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. Our final settlement is pending court approval, with an approval hearing set for February 3, 2015.

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, which, as disclosed in the Company’s prior periodic reports, was ultimately dismissed in our 2014 fiscal year. The Plaintiff had agreed to voluntarily dismiss the Valdez 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 Valdez 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 did. 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. This case has been dismissed and there is no further action required.

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

44

Table of Contents
(Dollars in thousands, except per share data and per unit data)

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, and have since returned, 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 were required of us in connection with this settlement, although we did pay the transportation costs of the equipment being returned. As a result, we recorded a gain of $113 related to this settlement in other income (expense), net in our condensed consolidated statement of operations for the six months ended October 31, 2014. As this matter has been resolved, no further action is required.
On February 7, 2014, we were served with a lawsuit filed by Vulcan Capital Corporation ("Vulcan") 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 Vulcan had with PlainsCapital Bank wherein Vulcan 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 Vulcan's default of the loan agreement, PlainsCapital Bank 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, but the case was transferred to Texas. We filed a motion to dismiss the case against the Company on October 9, 2014, and we are currently awaiting a ruling on the motion. 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.

ITEM 1A. RISK FACTORS.

For a detailed discussion of the risks and uncertainties associated with our business see "Risk Factors" in our 2014 Annual Report filed with the SEC on July 14, 2014, and amended on July 15, 2014. You should also carefully consider the following additional, known, material risk factors associated with our business and the markets and industry in which we operate. 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.
Recent changes in the markets for oil have caused a decline in prices that could adversely affect our borrowing base of our First Lien RBL and adversely impact our liquidity.
The price of oil has declined significantly starting in the second quarter of fiscal year 2015 and continuing to the date of this disclosure. Under our First Lien RBL, scheduled borrowing base redeterminations occur each February 1st and August 1st and the lenders have the right to call for an interim redetermination of the borrowing base once prior to February 1, 2015, and one time between any two redetermination dates after February 1, 2015. The decline in the price of oil could materially and adversely impact our borrowing base in future borrowing base redeterminations,

which could trigger repayment obligation under the First Lien Credit Agreement, to the extent our outstanding loans under the First Lien RBL exceed the redetermined borrowing base, and otherwise adversely impact our liquidity and our ability to pursue our drilling plans.

Our previously announced acquisition of Savant has not yet closed and may never close, and the operation of Savant post-acquisition will be subject to the risks and uncertainties inherent in integrating a new business into our operations.

Our ability to close the previously announced acquisition of Savant could be adversely impacted by the failure to receive final regulatory approvals from the State, events which adversely impact our liquidity generally and other critical events and there can be no guarantee that we will ever close that acquisition. In addition, once acquired, the operation of Savant will may find that we are unable to successfully integrate its business into our own or to exploit opportunities arising from its assets and location.

Table of Contents
(Dollars in thousands, except per share data and per unit data)

We currently have no operations on the North Slope of Alaska and this may heighten the difficulty in effectively overseeing, integrating and operating this business.

Changes in Alaska law relating to the availability, timing and amounts of tax credits for companies in our industry could adversely impact our liquidity and could adversely impact the economic viability of our drilling program.

If the State of Alaska were to alter or repeal legislation underlying tax credit programs available to oil and natural gas exploration and development companies operating within the State, including, but not limited to, changes in the amount of the tax credits available, the types of activities which qualify for the credits or in the timing of payment, those changes could materially and adversely impact our liquidity in a manner which could cause delays in, or hamper our ability to complete, our drilling plans. In addition, such changes could adversely impact our willingness to invest in certain exploration activities, infrastructure renewal, well development and the implementation of new technologies due to uncompetitive or negative returns on making such investments.

Our gas sales agreement with Alaska Pipeline Company is a volumetric contract with no express renewal provisions once the volume limits set forth in the agreement have been met, and we may be unable to replace that agreement with one that allows us to sell our gas production at similar prices.

We are party to a natural gas sales agreement with Alaska Pipeline Company, an affiliate of ENSTAR, pursuant to which most of our natural gas is presently sold. Currently, there is approximately 2.0 BCF remaining of a 10.0 BCF commitment under this agreement at a current price of approximately $7.00 per Mcf. When the agreement is fulfilled there is no right to renew it, no guarantee that we will be able to secure a new contract to replace it and no assurance that any new contract would be at favorable prices. Given our current production plans, we anticipate that we will have delivered the full 10 BCF called for under this agreement in September of 2015.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

None.

ITEM 5. OTHER INFORMATION.

None.

Table of Contents

ITEM 6. EXHIBITS.

The following documents are filed as a part of this report:

EXHIBIT NO.		DESCRIPTION
2.1	–	Purchase and Sale Agreement, dated November 22, 2013, by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC, as sellers and Cook Inlet Energy, LLC, as buyer (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 25,2013).
3.1	–	Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB (Commission file number 033-02249-FW) for the year ended December 31, 1995).
3.2	–	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB (Commission file number 033-02249-FW) for the year ended December 31, 1995).
3.3	–	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB (Commission file number 033-02249-FW) for the year ended December 31, 1995).
3.4	–	Certificate of Ownership and Merger and Articles of Merger between Triple Chip Systems, Inc. and Miller Petroleum, Inc. (incorporated by reference to Registrant's exhibits filed with the registration statement on Form SB-2, SEC File No. 333-53856, as amended).
3.5	–	Amended and Restated Charter of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
3.6	–	Amended and Restated Bylaws of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
3.7	–	Articles of Amendment to the Bylaws of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).
3.8	–	Articles of Amendment to the Charter of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 15, 2011).
3.9	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 2, 2012).
3.10	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on August 17, 2012).
3.11	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on September 4, 2012).
3.12	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Exhibit 3.20 to Registrant's Registration Statement on Form 8-A as filed on September 28, 2012).
3.13	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Exhibit 3.21 to Registrant's Registration Statement on Form 8-A as filed on September 26, 2013).
3.14	–	Amended and Restated Bylaws of Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 5, 2014).
†10.1	–	Withdrawal Agreement between the Company and David Voyticky, effective as of August 12, 2014 (incorporated by reference to Exhibit 5.1 to Registrant's Current Report on Form 8-K filed on August 12, 2014).
10.2	–	First Amendment to Credit Agreement dated as of August 11, 2014 among Miller Energy Resources, Inc. as Borrower, and KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on

		August 12, 2014).
10.3	–	Amendment No. 2 to Credit Agreement dated as of August 11, 2014 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on August 12, 2014).
10.4	–	Second Amendment to Credit Agreement dated as of August 19, 2014 among Miller Energy Resources, Inc. as Borrower, and KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K as filed on August 20, 2014).
10.5	–	Amendment No. 3 to Credit Agreement dated as of August 19, 2014 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on August 20, 2014).
†10.6	–	Separation Agreement dated September 14, 2014 between Deloy Miller and Miller Energy Resources, Inc. (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 18, 2014).
†10.7	–	Amendment to Employment Agreement with Scott M. Boruff, dated as of September 14, 2014 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on September 18, 2014).
†10.8	–	Employment Agreement with Carl F. Giesler, Jr., dated as of September 14, 2014 (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on September 18, 2014).
†10.9	–	Employment Agreement with David M. Hall, dated as of October 7, 2014 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 9, 2014).
10.10	–	Waiver and Third Amendment to Credit Agreement dated as of December 10, 2014 among Miller Energy Resources, Inc. as Borrower, and KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K as filed on December 10, 2014).
10.11	–	Waiver and Amendment No. 4 to Credit Agreement and Amendment No. 2 to Guarantee and Collateral dated as of December 10, 2014 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 10, 2014).
*31.1	–	Rule 13a-14(a)/15d-14(a) certification of Chief Executive Officer
*31.2	–	Rule 13a-14(a)/15d-14(a) certification of Chief Financial Officer
*32.1	–	Section 1350 certification of Chief Executive Officer
*32.2	–	Section 1350 certification of Chief Financial Officer
*101.INS	–	XBRL Instance Document
*101.SCH	–	XBRL Taxonomy Extension Schema Document
*101.CAL	–	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	–	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	–	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	–	XBRL Taxonomy Extension Definition Linkbase Document

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* Filed herewith.

† Indicates management contract or compensatory plan or arrangement.

Table of Contents

SIGNATURES

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

Dated: December 10, 2014

MILLER ENERGY RESOURCES, INC.

By: /s/ CARL F. GIESLER, JR.
Carl F. Giesler, Jr.
Chief Executive Officer
(Principal Executive Officer)

Dated: December 10, 2014

MILLER ENERGY RESOURCES, INC.

By: /s/ JEFFREY R. MCINTURFF
Jeffrey R. McInturff
Interim Chief Financial Officer
(Principal Financial Officer)