

MILLER ENERGY RESOURCES, INC.
Form 10-Q
March 12, 2015

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended January 31, 2015

OR

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

For the transition period from _____ to _____

Commission file number: 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 No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 No

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

| | | | |
|-------------------------|--------------------------|---------------------------|-------------------------------------|
| Large accelerated filer | <input type="checkbox"/> | Accelerated filer | <input checked="" type="checkbox"/> |
| Non-accelerated filer | <input type="checkbox"/> | Smaller reporting company | <input type="checkbox"/> |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act)

Yes No

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 February 26, 2015 was 46,664,223.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

MILLER ENERGY RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(Dollars in thousands, except share data)

| | January 31, 2015 | April 30, 2014 |
|--|---------------------|-------------------|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | \$2,239 | \$5,749 |
| Restricted cash | 147 | 679 |
| Accounts receivable, net of allowances of \$50 and \$252 | 14,064 | 6,409 |
| Alaska production credits receivable, net of allowances of \$2,390 and \$7,124 | 63,328 | 49,121 |
| Inventory | 3,697 | 5,102 |
| Prepaid expenses and other | 4,522 | 3,852 |
| Short-term portion of derivative instruments | 29,513 | 88 |
| Assets held for sale | 2,471 | 236 |
| Total current assets | 119,981 | 71,236 |
| OIL AND GAS PROPERTIES, NET | 189,722 | 644,827 |
| EQUIPMENT, NET | 51,691 | 35,369 |
| OTHER ASSETS: | | |
| Land | 15 | 1,848 |
| Restricted cash, non-current | 15,092 | 12,075 |
| Deferred financing costs, net | 3,364 | 803 |
| Long-term portion of derivative instruments | 12,027 | 26 |
| Other assets | 667 | 638 |
| Total assets | \$392,559 | \$766,822 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | \$59,380 | \$38,836 |
| Accrued expenses | 11,641 | 20,446 |
| Short-term portion of derivative instruments | — | 3,315 |
| Deferred income taxes | 7,620 | 2,858 |
| Current portion of long-term debt and capital leases | 29,553 | 9,459 |
| Liabilities associated with assets held for sale | 950 | — |
| Total current liabilities | 109,144 | 74,914 |
| OTHER LIABILITIES: | | |
| Deferred income taxes | 6,895 | 139,768 |
| Asset retirement obligation | 24,588 | 22,872 |
| Long-term portion of derivative instruments | — | 4,006 |
| Long-term debt and capital leases, less current portion | 196,252 | 174,743 |
| Other | 31 | — |
| Total liabilities | 336,910 | 416,303 |
| MEZZANINE EQUITY: | | |

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| | | |
|---|--------|--------|
| Series C Cumulative Preferred Stock, redemption amount of \$82,730 and \$78,124, 3,250,000 shares authorized, 3,250,000 and 3,069,968 shares issued and outstanding as of January 31, 2015 and April 30, 2014, respectively | 71,738 | 67,760 |
|---|--------|--------|

STOCKHOLDERS' EQUITY:

| | | |
|--|-----------|-----------|
| Series D Cumulative Redeemable Preferred Stock, redemption amount of \$83,984 and \$32,378, 4,000,000 shares authorized, 3,330,608 and 1,070,448 shares issued and outstanding as of January 31, 2015 and April 30, 2014, respectively | 60,090 | 30,041 |
| Series D Cumulative Redeemable Preferred Stock, 0 and 213,586 shares held in escrow as of January 31, 2015 and April 30, 2014, respectively | — | (5,000) |
| Common stock, \$0.0001 par, 500,000,000 shares authorized, 46,662,223 and 45,756,697 shares issued and outstanding as of January 31, 2015 and April 30, 2014, respectively | 5 | 4 |
| Additional paid-in capital | 110,693 | 98,788 |
| Retained earnings (accumulated deficit) | (186,877 |) 158,926 |
| Total stockholders' equity (deficit) | (16,089 |) 282,759 |
| Total liabilities and stockholders' equity | \$392,559 | \$766,822 |

See accompanying notes to the condensed consolidated financial statements.

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

| | Three Months Ended January 31, | | Nine Months Ended January 31, | |
|---|--------------------------------|--------------------|-------------------------------|---------------------|
| | 2015 | 2014 | 2015 | 2014 |
| REVENUES: | | | | |
| Oil sales | \$14,953 | \$16,348 | \$52,298 | \$47,012 |
| Natural gas sales | 4,768 | 118 | 16,430 | 671 |
| Other | 550 | 162 | 1,098 | 749 |
| Total revenues | 20,271 | 16,628 | 69,826 | 48,432 |
| OPERATING EXPENSES: | | | | |
| Lease operating expense | 8,803 | 4,410 | 24,392 | 15,226 |
| Transportation costs | 1,607 | 1,411 | 4,149 | 3,023 |
| Cost of purchased gas sold | 316 | — | 2,572 | — |
| Cost of other revenue | 640 | 256 | 1,305 | 844 |
| General and administrative | 7,358 | 7,587 | 34,770 | 21,092 |
| Alaska carried-forward annual loss credits, net | (21,508) |) — | (24,240) |) — |
| Exploration expense | 77,740 | 352 | 244,848 | 786 |
| Depreciation, depletion and amortization | 19,541 | 7,642 | 56,601 | 22,352 |
| Accretion of asset retirement obligation | 370 | 305 | 1,067 | 903 |
| Impairment of proved properties and other long-lived assets | 117,037 | — | 230,771 | — |
| Other operating expense, net | 900 | 1,250 | 904 | 1,250 |
| Total operating expense | 212,804 | 23,213 | 577,139 | 65,476 |
| OPERATING LOSS | (192,533) |) (6,585) |) (507,313) |) (17,044) |
| OTHER INCOME (EXPENSE): | | | | |
| Interest expense, net | (2,478) |) (407) |) (8,896) |) (4,051) |
| Gain (loss) on derivatives, net | 39,330 | 1,677 | 55,516 | (5,589) |
| Other income, net | 404 | 42 | 559 | 26 |
| Total other income (expense) | 37,256 | 1,312 | 47,179 | (9,614) |
| LOSS BEFORE INCOME TAXES | (155,277) |) (5,273) |) (460,134) |) (26,658) |
| Income tax benefit | 3,016 | 2,171 | 128,111 | 11,640 |
| NET LOSS | (152,261) |) (3,102) |) (332,023) |) (15,018) |
| Accretion of Series C and D preferred stock | (1,271) |) (817) |) (3,005) |) (1,935) |
| Series C and D preferred stock cumulative dividends | (4,369) |) (2,905) |) (10,775) |) (7,573) |
| NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS | \$(157,901) |) \$(6,824) |) \$(345,803) |) \$(24,526) |
| LOSS PER COMMON SHARE: | | | | |
| Basic | \$(3.39) |) \$(0.15) |) \$(7.47) |) \$(0.56) |
| Diluted | \$(3.39) |) \$(0.15) |) \$(7.47) |) \$(0.56) |
| WEIGHTED AVERAGE NUMBER OF COMMON SHARES: | | | | |
| Basic | 46,644,887 | 44,886,838 | 46,311,958 | 44,141,222 |
| Diluted | 46,644,887 | 44,886,838 | 46,311,958 | 44,141,222 |

See accompanying notes to the condensed consolidated financial statements.

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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 | — | — | — | — | — | (332,023) | (332,023) |
| Series C preferred stock dividends | — | — | — | — | — | (6,309) | (6,309) |
| Accretion of Series C preferred stock | — | — | — | — | — | (2,179) | (2,179) |
| Issuance of Series D preferred stock | 2,260,160 | 34,223 | — | — | — | — | 34,223 |
| Series D preferred stock dividends | — | — | — | — | — | (4,466) | (4,466) |
| Accretion of Series D preferred stock | — | 826 | — | — | — | (826) | — |
| Issuance of equity for services | — | — | — | — | 615 | — | 615 |
| Issuance of equity for compensation | — | — | 575,587 | — | 9,881 | — | 9,881 |
| Exercise of equity rights | — | — | 329,939 | 1 | 1,409 | — | 1,410 |
| Balance at January 31, 2015 | 3,330,608 | \$60,090 | 46,662,223 | \$5 | \$110,693 | \$ (186,877) | \$(16,089) |

See accompanying notes to the condensed consolidated financial statements.

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

| | Nine Months Ended January 31, | |
|--|-------------------------------|------------------|
| | 2015 | 2014 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net loss | \$(332,023 |) \$(15,018 |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 56,601 | 22,352 |
| Amortization of deferred financing fees and debt discount | 1,288 | 1,113 |
| Expense from issuance of equity | 10,857 | 5,120 |
| Non-cash exploration expenses | 242,980 | 157 |
| Impairment of proved properties and other long lived assets | 230,771 | — |
| Deferred income taxes | (128,111 |) (11,640 |
| Derivative contracts: | | |
| (Gain) loss on derivatives, net | (55,516 |) 5,589 |
| Cash settlements received (paid) | 6,769 | (2,765 |
| Alaska carried-forward annual loss credits, net | (24,240 |) — |
| Accretion of asset retirement obligation | 1,067 | 903 |
| Other, net | 2,350 | 1,949 |
| Changes in operating assets and liabilities (excluding effects of acquisitions): | | |
| Receivables | 14,694 | 5,084 |
| Inventory | (232 |) 372 |
| Prepaid expenses and other assets | (876 |) (1,788 |
| Accounts payable, accrued expenses and other | 593 | 3,849 |
| NET CASH PROVIDED BY OPERATING ACTIVITIES | 26,972 | 15,277 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties | (110,953 |) (94,388 |
| Purchase of equipment and improvements | (16,318 |) (986 |
| Proceeds from Alaska expenditure and exploration based credits | 36,809 | 18,561 |
| Prepayment of drilling costs | — | (2,302 |
| Cash paid for Savant acquisition, net of cash acquired | (1,448 |) — |
| Proceeds from sale of assets | 4,191 | — |
| Deposits for potential acquisition | — | (3,000 |
| NET CASH USED IN INVESTING ACTIVITIES | (87,719 |) (82,115 |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Cash dividends | (9,312 |) (5,646 |
| Payments on debt | (16,917 |) — |
| Proceeds from borrowings | 54,000 | 20,000 |
| Proceeds from capital lease obligations | 3,250 | — |
| Principal payments on capital lease obligations | (494 |) — |
| Debt acquisition costs | (3,191 |) (1,900 |
| Issuance of preferred stock | 32,357 | 62,704 |
| Equity issuance costs | (1,781 |) (3,893 |
| Exercise of equity rights | 1,410 | 4,538 |

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| | | |
|--|----------|----------|
| Restricted cash | (2,085 |) 1,665 |
| Other | — | 3 |
| NET CASH PROVIDED BY FINANCING ACTIVITIES | 57,237 | 77,471 |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | (3,510 |) 10,633 |
| | | |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | 5,749 | 2,551 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | \$2,239 | \$13,184 |
| SUPPLEMENTARY CASH FLOW DATA: | | |
| Cash paid for interest | \$18,492 | \$5,805 |
| SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES: | | |
| Increase in capital expenditures included in accounts payable and accrued expenses | \$5,217 | \$32,572 |
| Reduction of oil and gas properties and equipment from applications for Alaska expenditure and exploration based credits | \$45,979 | \$28,906 |
| Accretion of preferred stock | \$3,005 | \$1,935 |
| Issuance of Series D Preferred Stock held in escrow | \$— | \$5,000 |
| Issuance of Series D Preferred Stock for Anchor Point Pipeline | \$5,446 | \$— |
| Promissory note for Savant acquisition | \$2,000 | \$— |

See accompanying notes to the condensed consolidated financial statements.

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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, Savant Alaska, LLC, Nutaaq Operating, LLC, Nutaaq Pipeline, 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.

Miller Energy Resources is 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, as well as Alaska's North Slope. The accounting policies used by the Company and its 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

The Company's significant accounting policies are consistent with those disclosed in Miller's Annual Report on Form 10-K for the year ended April 30, 2014.

Principles of Consolidation

The accompanying condensed consolidated financial statements include the Company's consolidated accounts after elimination of intercompany balances and transactions. The condensed consolidated financial statements also include the accounts of all investments in which Miller, either through direct or indirect ownership, has 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

The Company follows 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

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MILLER ENERGY RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(Unaudited)

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

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

The Company determines 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. The Company computes 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 January 31, 2015, our cumulative preferred dividends were \$10,775.

Deferred Escalating Minimum Rent

Certain of Miller's 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, the Company recognizes the related rental expense on a straight-line basis over the life of the lease, beginning with the point at which Miller obtains control and possession of the leased properties, and records 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 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" which 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

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MILLER ENERGY RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(Unaudited)

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

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.

In November 2014, the FASB issued ASU 2014-16, "Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity."

ASU 2014-16 clarifies how current U.S. GAAP should be interpreted in evaluating the economic characteristics and risk of a host contract in a hybrid financial instrument that is issued in the form of a share. In addition, ASU 2014-16 was issued to clarify that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features, such as the relative strength of the debt-like or equity-like terms and features given the facts and circumstances, when considering how to weight those terms and features. The effects of initially adopting ASU 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU 2014-16 is effective fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption in an interim period is permitted. The Company will continue to determine the effects, if any, of ASU 2014-16 on its consolidated financial statements.

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 representative of a strategic shift which 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 the Company's condensed consolidated financial statements.

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

3. ACQUISITIONS AND DIVESTITURES

Merger Agreement with Savant Alaska, LLC

On May 8, 2014, the Company entered into an Agreement and Plan of Merger, as amended on December 11, 2014, with Savant Alaska, LLC ("Savant") to acquire Savant, subject to due diligence and regulatory approval, for \$9,000 (of which \$6,000 was paid in cash and \$3,000 was financed through three promissory notes in \$1,000 increments, of which \$1,000 was repaid as of January 31, 2015). The Company formed a wholly-owned subsidiary, Miller Energy Colorado 2014-1, LLC, which merged with Savant to facilitate the acquisition. Savant was the surviving entity upon completion of the merger, and is now a wholly-owned subsidiary of Miller. Acquisition-related costs of \$396 were expensed by the Company. We recorded a net loss of \$1,560 in our condensed consolidated statement of operation for the three months ended January 31, 2015 related to Savant. Miller acquired a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases as a result of this merger. 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 acquired 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, the crude oil pipeline running approximately 25 miles in length from the Badami Unit to the Endicott Pipeline and the Duck Island Unit. Production from the Savant assets was approximately 1,000 bopd gross (600 bopd net) during January 2015.

The transaction closed on December 11, 2014, after regulatory approval was obtained.

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The purchase of Savant 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 Savant and the allocation of the purchase price to the assets acquired and liabilities assumed which 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 Allocation |
|--|------------------------------|
| Cash Consideration Paid and Promissory Notes Issued for the Acquisition: | |
| Cash paid | \$6,000 |
| Promissory notes | 3,000 |
| Consideration paid | \$9,000 |
| Preliminary Allocation of Assets Acquired and Liabilities Assumed: | |
| Current assets | \$9,772 |
| Proved oil and gas properties | 1,840 |
| Crude oil pipeline | 585 |
| Support equipment | 592 |
| Other assets | 408 |
| Current liabilities | (2,757) |
| Asset retirement obligation | (1,440) |
| Fair value of assets acquired and liabilities assumed | \$9,000 |

In conjunction with the acquisition of Savant, it was necessary to estimate the value of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and those requiring the most judgment, involved the estimated fair value of the reserves, pipelines, and support equipment. Assumptions were also made regarding the retirement obligation. With respect to the fair values, these assumptions are considered Level 3 inputs.

The following pro forma financial information reflects the consolidated results of our operations as if the Savant merger had occurred May 1, 2013. The pro forma information includes adjustments for operating expenses, depreciation and depletion of the acquired property and equipment, interest expense for acquisition debt and income taxes. The pro forma information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed date:

| | Three Months Ended January 31, | | Nine Months Ended January 31, | |
|--|--------------------------------|------------|-------------------------------|-------------|
| | 2015 | 2014 | 2015 | 2014 |
| Revenues | \$21,737 | \$22,747 | \$83,322 | \$67,892 |
| Net loss attributable to common shareholders | \$(159,430) | \$(5,219) | \$(344,158) | \$(16,622) |
| Net loss per common share, basic and diluted | \$(3.42) | \$(0.12) | \$(7.43) | \$(0.38) |

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 213,586 shares 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 which have been included in the Company's condensed

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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 Allocation |
|--|------------------------------|
| Consideration Issued for Acquisition: | |
| Series D Preferred Stock | \$5,446 |
| Preliminary Allocation of Assets Acquired and Liabilities Assumed: | |
| Natural gas pipeline and pipeline support equipment | \$5,687 |
| Asset retirement obligation | (241) |
| Fair value of assets acquired and liabilities assumed | \$5,446 |

In conjunction with the acquisition of the Anchor Point Pipeline, it was necessary to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and those 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.

Divestiture of Tennessee Assets

During the nine months ended January 31, 2015, the Company closed the previously announced sale of substantially all of its Tennessee oil and gas assets, including our oil and gas inventory, yielding proceeds of \$4,191 in cash.

4. MAJOR CUSTOMERS AND CONCENTRATIONS OF CREDIT RISK

For the three months ended January 31, 2015 and 2014, one customer accounted for 72% and 95%, respectively, and a second customer accounted for 19% and 0%, respectively, of Miller's consolidated total revenues. For the nine months ended January 31, 2015 and 2014, one customer accounted for 79% and 93%, respectively, and a second customer accounted for 10% and 0%, respectively, of the Company's consolidated total revenues. Two customers accounted for 14% and 11% of Miller's consolidated accounts receivable as of January 31, 2015. One customer accounted for 5% of the Company's 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. The Company experienced no credit losses of significance during the three and nine months ended January 31, 2015 or 2014.

The Company maintains its cash and cash equivalents (including restricted cash), which at times may exceed federally insured amounts, in highly rated financial institutions. As of January 31, 2015, the Company held \$1,378 in excess of the \$250 limit insured by the Federal Deposit Insurance Corporation.

The Company has a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. The Company attempts 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. The Company also enters into master netting agreements to mitigate counterparty performance and credit risk. During the three and nine months ended January 31, 2015 and 2014, Miller did not incur any significant losses due to counterparty bankruptcy filings. The Company assesses its credit exposure on a net basis to reflect master netting agreements in place with certain

counterparties. Credit exposure is offset to each counterparty with amounts the Company owes the counterparty under derivative contracts.

5. RELATED PARTY TRANSACTIONS

The Company uses a number of contract labor companies to provide on demand transportation and labor at Miller's 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 immediate family

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members of David Hall, the Company's Chief Operating Officer ("COO"). For the three and nine months ended January 31, 2015, the Company recorded capital and lease operating expenses related to H&H Industrial of \$617 and \$2,320, respectively. The Audit Committee of Miller's Board of Directors determined that the amounts paid by the Company 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 (subject to approval by the Compensation Committee of our Board of Directors which occurred on March 9, 2015) with Deloy Miller under which he agreed to assist with its oil and gas related matters, including assisting with the Company's strategic planning, providing management with drilling advice, and other consulting services the Company 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 its common stock at an exercise price of \$1.35 per share, vesting in equal installments on the first and second anniversary of the date the parties entered into the consulting agreement. In addition, the Company has agreed to assign over to Mr. Miller a life insurance policy covering Mr. Miller, with respect to which the Company is currently listed as beneficiary. When assigned, Mr. Miller would be free to designate a new beneficiary; however, the Company would continue to pay the premiums on this policy until the expiration of the two-year term of our consulting agreement with him. 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 the Company's Board of Directors determined that the consideration given by the Company for the services to be performed was fair and entering into the agreement was in the best interest of the Company.

6. OIL AND GAS PROPERTIES AND EQUIPMENT

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

| | January 31, 2015 | April 30, 2014 |
|-----------------------------|---------------------|-------------------|
| Property costs: | | |
| Proved property | \$476,694 | \$467,740 |
| Unproved property | 47,984 | 243,230 |
| Total property costs | 524,678 | 710,970 |
| Less: Accumulated depletion | (334,956) | (66,143) |
| Oil and gas properties, net | \$189,722 | \$644,827 |

On January 31, 2015, the significant and continued decline in crude oil prices during the third quarter of fiscal 2015 was identified as an impairment-related triggering event for proved properties. The Redoubt Unit and West McArthur River 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 and the West McArthur River Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved and unproved properties of the Redoubt Unit and West McArthur River Unit of \$81,480 and \$67,586, respectively. The factors used to estimate the fair value of the Redoubt Unit and the West McArthur River 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, the Company has categorized the amounts as Level 3 inputs. As of January 31, 2015, the proved and unproved properties of the Redoubt Unit were written down to their estimated fair value of \$42,044 and \$2,318, respectively. Also as of January 31, 2015, the proved and unproved properties of the West McArthur River Unit were written down to their estimated fair

value of \$75,433 and \$1,252, respectively. Also during the third quarter of fiscal 2015, the Company recorded a charge to exploration expense of \$40,443 for other unproved properties, including Olson Creek #1 and Otter #1 due to changes in our drilling plans.

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 the Redoubt Unit 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, the Company has categorized the amounts as Level 3 inputs.

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During the second and third quarters of fiscal 2015, the Company recorded a charge to exploration expense of \$18,800 for Olson 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. During the fiscal third quarter, we recognized an impairment of \$4,205 to write down certain Tennessee-related assets classified as held for sale as of January 31, 2015 that remained subsequent to the sale of substantially all of our Tennessee oil and gas properties to reflect the expected respective sales price of those assets.

Equipment is summarized as follows:

| | January 31, 2015 | April 30, 2014 |
|--------------------------------------|---------------------|-------------------|
| Machinery and equipment | \$2,821 | \$7,759 |
| Vehicles | 1,425 | 1,877 |
| Buildings | 2,043 | 2,726 |
| Office equipment | 1,054 | 1,108 |
| Leasehold improvements | 676 | 527 |
| Drilling rigs | 44,581 | 30,210 |
| Capital lease asset | 4,022 | 1,500 |
| Pipeline and pipeline support assets | 6,255 | — |
| | 62,877 | 45,707 |
| Less: Accumulated depreciation | (11,186 |) (10,338 |
| Equipment, net | \$51,691 | \$35,369 |

The Company classified its aircraft as an asset held for sale on the condensed consolidated balance sheets as of April 30, 2014 and January 31, 2015. The aircraft is recorded at estimated fair value less cost to sell.

During the nine months ended January 31, 2015, substantially all of the remaining portion of the Company's Tennessee assets were reclassified and presented as assets held for sale. The Company estimates the fair value of these assets and liabilities to be \$2,331 and \$950, respectively. An impairment charge of \$5,524 was recorded during the nine months ended January 31, 2015, 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, the Company has categorized the amounts as Level 3 inputs.

Depreciation, depletion and amortization consisted of the following:

| | For the Nine Months Ended January 31, | |
|--|--|----------|
| | 2015 | 2014 |
| Depletion of oil and gas related assets | \$53,240 | \$19,158 |
| Depreciation and amortization of equipment | 3,361 | 3,194 |
| Total | \$56,601 | \$22,352 |

The Company has obtained multiple reserve reports in the last twelve months due to Miller's acquisition and drilling activity in Alaska. The reserve reports have provided incremental information to allow the Company 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, the Company entered into a Purchase and Sale Agreement with Teras Oilfield Support Limited which granted Miller the right to purchase the Glacier Drilling Rig #1, a Mesa 1000 carrier-mounted land drilling rig, which Miller has renamed Rig 37, and related equipment. During the nine months ended January 31, 2015, the Company paid \$7,000 in connection with the acquisition of Rig 37.

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Acquisition of Rig 36 and Related Capital Lease

On May 5, 2014, the Company entered into a Rig Equipment Purchase Agreement with Baker Process, Inc. to purchase a 2400 HP rig, which Miller has 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. The Company has drawn \$3,250 under the capital lease.

7. DERIVATIVE INSTRUMENTS

Derivative Instruments

Commodity Derivatives

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

Miller has experienced, and could continue to experience, earnings volatility due to fluctuations in the fair value of these commodity derivative contracts. Miller's reported cash flows are affected by cash settlements, and its 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 January 31, 2015, the Company had the following open crude oil derivative positions. All are priced based on the Brent crude oil futures as traded on the Intercontinental Exchange.

| Production Period ending April 30, | Fixed - Price Swaps | |
|------------------------------------|---------------------|------------------------------------|
| | Bbls | Weighted Average Fixed Price |
| 2015 | 191,400 | \$97.09 |
| 2016 | 787,600 | \$95.36 |
| 2017 | 232,600 | \$93.97 |

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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 Miller's master netting arrangements.

| Derivatives not designated as hedging instruments under ASC 815 | Asset Derivatives January 31, 2015 | | April 30, 2014 | | Liability Derivatives January 31, 2015 | | April 30, 2014 | |
|---|--|------------|--|------------|--|------------|--|------------|
| | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| Commodity derivatives | Short-term portion of derivative instruments | \$29,513 | Short-term portion of derivative instruments | \$88 | Short-term portion of derivative instruments | \$— | Short-term portion of derivative instruments | \$(3,315) |
| Commodity derivatives | Long-term portion of derivative instruments | 12,027 | Long-term portion of derivative instruments | 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 | | \$41,540 | | \$114 | | \$— | | \$(7,321) |

Offsetting of Derivative Assets and Liabilities

The following table presents the Company's gross and net derivative assets and liabilities:

| | Gross Amount Presented on Balance Sheet | Netting Adjustments (a) | Net Amount |
|--|---|-------------------------|------------|
| January 31, 2015 | | | |
| Derivative assets with right of offset or master netting agreements | \$41,540 | \$— | \$41,540 |
| 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 | | For the Nine Months Ended January | |
|---------------------------------|----------------------------|---------|-----------------------------------|-----------|
| | January 31, | | 31, | |
| | 2015 | 2014 | 2015 | 2014 |
| Gain (loss) on derivatives, net | \$39,330 | \$1,677 | \$55,516 | \$(5,589) |

As of January 31, 2015, Miller did not maintain any derivative instruments that were classified as fair value hedges or trading securities. In addition, as of January 31, 2015, the Company did not maintain any derivative instruments containing credit risk contingencies.

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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 | | |
|--------------------------------|-------------------------|-----------|---------|
| | Level 1 | Level 2 | Level 3 |
| At January 31, 2015 | | | |
| Commodity derivative asset | \$— | \$41,540 | \$— |
| Commodity derivative liability | — | — | — |
| Total | \$— | \$41,540 | \$— |
| 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 nine months ended January 31, 2015.

9. DEBT

As of January 31, 2015 and April 30, 2014, the Company had the following debt obligations:

| | January 31, 2015 | April 30, 2014 |
|--|---------------------|-------------------|
| Second Lien Credit Facility | \$175,000 | \$175,000 |
| Debt discount related to Second Lien Credit Facility | (2,639) |) (3,296) |
| First Lien RBL | 44,000 | — |
| Savant Promissory Notes payable | 2,000 | — |
| Gunsight Promissory Note payable | — | 950 |
| Apollo prepayment and extension fee note payable | 2,306 | 9,223 |
| Capital lease obligation | 2,756 | — |
| Series B Preferred Stock | 2,382 | 2,325 |
| Total debt obligations | 225,805 | 184,202 |
| Less: Current maturities | (29,553) |) (9,459) |
| Total debt less current maturities | \$196,252 | \$174,743 |

As of January 31, 2015, the Company's current maturities of long term debt related to amounts that are due to our lenders within the next twelve months in accordance with provisions in the underlying agreements.

Second Lien Credit Facility

On February 3, 2014, the Company refinanced its \$100,000 credit facility with Apollo Investment Corp. ("Apollo") (the "Prior Credit Facility") by entering into a new Credit Agreement (as amended, the "Second Lien Credit Agreement") among the

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Company, as borrower, Apollo, as administrative agent (in that capacity, the "Second Lien Agent"), and Apollo and certain affiliates of Highbridge Capital Strategies (the "Second Lien Lenders") which set forth the terms of a credit facility of \$175,000 (as amended, 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 the Company 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. Under the terms of the Second Lien Credit Facility, Miller was permitted to enter into a reserve-based revolving credit facility on 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. The Company entered into a credit agreement for a revolving credit facility (the "First Lien Loan Agreement"), among the Company, 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 senior secured, reserve-based revolving credit facility of up to \$250,000 (the "First Lien RBL"). In connection with the Company's 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 January 31, 2015, there was an event of default under the Second Lien Credit Facility arising from a delay in our issuing a mortgage in favor of the Second Lien Lenders covering a right-of-way lease underlying our North Fork Pipeline (the "Second Lien Technical Default"). Additionally, the Company was not in compliance with certain of the required financial covenants as of January 31, 2015 (the "Second Lien Covenant Default"), although the Company was in compliance with the production covenant and other covenants. The Second Lien Technical Default and Second Lien Covenant Default were waived or otherwise remedied by the March 2015 Second Lien Amendment (as defined below under Note 16, Subsequent Events). While we believe we will comply with the covenants in the Second Lien Credit Facility for the next twelve months, if we are unable to do so or are unable to obtain a waiver from our lender, our debt would become immediately due and payable and we would not be able to utilize our assets to satisfy our obligations.

The Company 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 \$171,525 and \$176,785 as of January 31, 2015 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, the Company, along with all of its then 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 the Company's consolidated subsidiaries (other than MEI and Nutaaq Pipeline, LLC) 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, the Company 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.

On August 11, 2014, the Company 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.

On August 19, 2014, the Company entered into Amendment No. 3 to the Second Lien Credit Agreement, which (i) increased the total amount of obligations we may enter into under capital leases from time to time, (ii) allowed us to make certain investments in Savant, and (iii) increased the amount of preferred stock that we may issue, among other things.

On December 10, 2014, the Company entered into Waiver and Amendment No. 4 to Credit Agreement and Amendment No. 2 to Guarantee and Collateral Agreement (the "December Second Lien Amendment") to our Second Lien Credit Agreement and our Second Lien Guarantee. The December Second Lien Amendment, among other things, (1) makes conforming amendments

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to our leverage and interest covenants, matching those in the December First Lien Amendment (as defined below), (2) establishes approved plans of development (the "Plans"), defines "Permitted Capital Expenditures," adds requirements for the development of our drilling program with 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 (as with the December First Lien Amendment, up to \$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 the December 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 the Company elects to pay such interest in kind, by 2% per annum) until the Company has raised \$20,000 in net proceeds from the issuance of equity interests of the Company, provided that if the Company has not raised such amounts within four months, the change in the interest rate becomes permanent and (12) adds additional events of default.

First Lien RBL

On June 2, 2014, Miller 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 the Company 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).

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 due to a delay in our issuing mortgage in favor of the Second Lien Lenders covering a right-of-way lease

underlying our North Fork Pipeline, there was an event of default under the First Lien Loan Agreement's cross default provision (the "First Lien Technical Default"). Additionally, the Company was not in compliance with (1) a related covenant to issue a mortgage covering that right-of-way lease in favor of the RBL Lenders and (2) certain of the required financial covenants as of January 31, 2015 (the "First Lien Covenant Default"), although the Company was in compliance with the production covenant and other covenants. While we believe we will comply with the covenants in the First Lien Credit Facility for the next twelve months, if we are unable to do so or are unable to obtain a waiver from our lender, our debt would become immediately due and payable and we would not be able to utilize our assets to satisfy our obligations. The First Lien Technical Default and First Lien Covenant Default were waived or otherwise remedied by the March 2015 First Lien Amendment (as defined 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

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base. On June 20, 2014, Miller requested an additional \$10,000, which was funded on June 24, 2014. On August 1, 2014, the Company drew down \$16,000. On December 11, 2014, the Company drew \$3,000 down and an additional \$5,000 on December 31, 2014. The Company repaid borrowings of \$10,000 during the nine months ended January 31, 2015. 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, the Company, along with all of its then consolidated subsidiaries (other than MEI and Miller Energy Colorado 2014-1, LLC), 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 the Company's consolidated subsidiaries (other than MEI and Nutaaq Pipeline, LLC) have guaranteed the obligations under the First Lien RBL. Along with the aforementioned subsidiaries, Miller has granted a security interest in substantially all of its assets to secure the performance of the obligations arising under the First Lien RBL.

On August 11, 2014, the Company 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, the Company entered into the Second Amendment to our First Lien Loan Agreement, which (i) increases the total amount of obligations we may enter into under capital leases from time to time, (ii) allows us to make certain investments in Savant, and (iii) increases the amount of preferred stock that we may issue, among other things.

On December 10, 2014, the Company entered into a Third Amendment (the "December First Lien Amendment") to the First Lien Credit Agreement and the First Lien Guarantee. The December First Lien Amendment, among other things, (1) amends our leverage and interest covenants, (2) establishes the Plans, defines "Permitted Capital Expenditures," 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, in each case in a manner consistent with the December Second Lien Amendment, (3) permits us to issue an additional \$25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (up to \$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 RBL Administrative Agent (for the benefit of the RBL 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 RBL 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 RBL Lenders to exceed \$50,000 in the aggregate prior to next redetermination date for our borrowing base, scheduled for February 1, 2015 and (11) required that, following receipt of our tax credit payment from the State of Alaska in

February of 2015, we not allow the aggregate revolving credit exposure of the RBL Lenders to exceed \$40,000.

Savant Promissory Notes Payable

As merger consideration for the Savant acquisition, three \$1,000 promissory notes were issued to the former owners of Savant Alaska, LLC. The notes mature on December 18, 2014, February 28, 2015 and June 30, 2015. The Company had \$2,000 of promissory notes outstanding at January 31, 2015. The December 18, 2014 promissory note was paid and, subsequent to January 31, 2015, the February 28, 2015 promissory note was paid. These promissory notes do not bear any interest if paid on or before the maturity date. Any payment of the promissory note not paid on or before the maturity date shall bear interest at the default interest rate of 1.5% per month. No interest has been paid on the promissory notes.

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 January 31, 2015 and April 30, 2014, the fair value of Series B Preferred Stock was \$2,075 and

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\$2,197, respectively, as calculated using the discounted cash flow method. The fair value of the Series B Preferred Stock is classified as a Level 3 measurement as the fair value is calculated using a discounted cash flow model. The following table summarizes the Series B Preferred Stock dividend activity for the nine months ended January 31, 2015.

| Series | Declaration Date | Dividend per Share | Annualized Percentage Rate | Par Value | Accrual Period | Record Date | Payment Date |
|--------|------------------|--------------------|----------------------------|------------|-------------------------------|-------------------|-------------------|
| B | July 28, 2014 | \$6.05 | 12 | % \$100.00 | Mar. 1 - Aug. 31, 2014 | August 15, 2014 | September 2, 2014 |
| B | January 30, 2015 | \$5.95 | 12 | % \$100.00 | Sept. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |

Debt Issue Costs

As of January 31, 2015 and April 30, 2014, the Company's unamortized deferred financing costs were \$3,364 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.

10. ASSET RETIREMENT OBLIGATIONS

The following table presents changes to the Company's asset retirement obligation ("ARO") liability for the nine months ended January 31, 2015 and 2014:

| | 2015 | 2014 |
|---|----------|----------|
| Asset retirement obligation, as of April 30, | \$22,872 | \$19,890 |
| Additions | 2,206 | 196 |
| Revisions | (100) |) — |
| Sold wells | (1,495) |) — |
| Accretion expense | 1,067 | 903 |
| Settlements | (121) |) (22) |
| North Fork properties purchase price adjustment | 159 | — |
| Asset retirement obligation, as of January 31, | \$24,588 | \$20,967 |

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, the Company's 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 the Company's Board of Directors on March 10, 2014, and approved by its 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 the Company's Board of Directors on September 14,

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2014, and approved by its shareholders on October 30, 2014. The share-based compensation plans allow Miller to offer its employees, officers, directors and others an opportunity to acquire a proprietary interest in the Company and enables the Company to attract, retain, motivate and reward such persons in order to promote its 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 the Company's Compensation Committee. At January 31, 2015 and April 30, 2014, there were 187,500 and 2,500 shares available under the 2010 Miller Petroleum, Inc. Stock Plan, respectively, and 3,157,256 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 nine months ended January 31, 2015 of approximately \$703 and \$10,242, respectively, and \$1,343 and \$4,368 for the three and nine months ended January 31, 2014, respectively. The Company also recognized non-employee expense related to warrants issued for the three and nine months ended January 31, 2015 of approximately \$41 and \$615, respectively, and \$203 and \$752 for the three and nine months ended January 31, 2014, respectively.

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 | 2,720,500 | 4.53 |
| Exercised | (329,939 |) 4.37 |
| Cancelled | (1,380,460 |) 4.95 |
| Ending balance | 16,031,448 | 4.93 |
| Options and warrants exercisable at January 31, 2015 | 13,760,634 | \$4.96 |

The following table summarizes stock options and warrants outstanding, including exercisable shares at January 31, 2015:

| 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 \$1.24 | 1,361,000 | 1.3 | \$0.63 | 1,311,000 | \$0.61 |
| \$2.00 to \$4.99 | 3,673,001 | 7.0 | 4.04 | 2,227,687 | 3.77 |
| \$5.15 to \$5.53 | 4,137,447 | 2.2 | 5.32 | 3,641,947 | 5.33 |
| \$5.68 to \$5.94 | 3,435,000 | 5.8 | 5.90 | 3,195,000 | 5.92 |
| \$6.00 to \$6.95 | 3,425,000 | 1.9 | 6.13 | 3,385,000 | 6.12 |
| | 16,031,448 | 3.9 | \$4.93 | 13,760,634 | \$4.96 |

The following table summarizes restricted stock activity for the nine months ended January 31, 2015:

| | | |
|----------------------------|------------|---|
| Unvested at April 30, 2014 | 465,432 | |
| Granted | 945,655 | |
| Vested | (1,182,587 |) |
| Cancelled | (28,000 |) |

Unvested at January 31, 2015

200,500

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12. STOCKHOLDERS' EQUITY

Common Stock

At January 31, 2015, the Company had 46,662,223 shares of common stock outstanding. The Company issued 905,526 shares during the nine months ended January 31, 2015, of which 575,587 shares were issued to employees for compensation, and 329,939 shares were related to the exercise of equity rights.

Series C Preferred Stock

During the nine months ended January 31, 2015, the Company sold 180,032 shares of its 10.75% Series C Cumulative Redeemable Preferred Stock (the "Series C Preferred Stock"), with a redemption value of \$25.00 per share, pursuant to an "at-the-market" offering, yielding net proceeds of \$1,799. The dividend yield on these "at-the-market" shares is 27% and the redemption amount is \$4,583.

Series D Preferred Stock

During the nine months ended January 31, 2015, the Company sold 1,296,574 shares of its 10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock (the "Series D Preferred Stock"), with a redemption value of \$25.00 per share, pursuant to an "at-the-market" offering, yielding net proceeds of \$11,753. The dividend yield on these "at-the-market" shares is 29% and the redemption amount is \$32,698.

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

Dividends Declared on Preferred Stock

The following table summarizes the Series C Preferred Stock and Series D Preferred Stock dividend activity for the nine months ended January 31, 2015.

| 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 |
| C | January 30, 2015 | \$0.67 | 10.75 | % \$25.00 | Dec. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |
| D | January 30, 2015 | \$0.66 | 10.5 | % \$25.00 | Dec. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |

Fair Value Measurements

The estimated fair value of the Company's Series C and Series D Preferred Stock was \$41,373 and \$36,670, respectively, as of January 31, 2015, and \$77,976 and \$31,330, respectively, as of April 30, 2014.

13. INCOME TAXES

Under ASC 740, companies are required to assess whether a valuation allowance should be established against their deferred tax assets based on the consideration of all available evidence using a "more likely than not" standard. In making such judgments, significant weight is given to evidence that can be objectively verified. We are in a three year cumulative pre-tax loss position as of January 31, 2015. A cumulative loss position is considered significant negative evidence in assessing the realizability of a deferred tax asset and is difficult to overcome. We did not consider future taxable income, tax planning strategies, or income in carry back years in determining the realizability of our deferred tax assets. Our estimate of the realization of the deferred tax assets was solely based on future reversals of existing taxable temporary differences. This resulted in the imposition of an additional valuation allowance of approximately \$64,273 during the nine months ended January 31, 2015. Our provision for income taxes is based on the actual year-to-date effective rate, which includes the adjustment for the increase in the valuation allowance, as this

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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 quarters and year-to-dates ended January 31, 2015 and January 31, 2014 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 January 31, 2015 is a benefit of (28%). The principal differences in the Company's effective tax rate (benefit) for this period and the federal statutory rate of 35% are state and local income taxes net of federal benefit, the change in state rate and a valuation allowance against our deferred tax assets. No cash payments of income taxes were made during the year-to-date period ended January 31, 2015, 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%)

The Company recognizes a receivable when the amount of the credit is reasonably estimable and receipt is probable. For expenditure and exploration based credits, which Miller receives in the ordinary course of business, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, which Miller receives in the ordinary course of business, the credit is recorded as a reduction to the Alaska production tax. The Company 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 its operating expenses on the condensed consolidated statements of operations.

| | | |
|---|----------|---|
| Balance, April 30, 2014 | \$49,121 | |
| Alaska carried-forward annual loss credits, net ¹ | 24,240 | |
| Applications for expenditure and exploration based credits ¹ | 45,979 | |
| Cash collections for expenditure and exploration based credits | (56,012) |) |
| Balance, January 31, 2015 | \$63,328 | |

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 nine months ended January 31, 2015, the Company recorded net carried-forward annual loss credits of \$24,240. The Company has reduced the basis of capitalized assets by a cumulative total of \$80,297 for expenditure and exploration credits. The reductions are recorded on Miller's condensed consolidated balance sheets in oil and gas properties and equipment. As of January 31, 2015 and April 30, 2014, the Company had outstanding net receivables from the State of Alaska in the amount of \$63,328 and \$49,121, respectively.

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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. 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. A bench trial was held January 20, 2015 through January 22, 2015. We received the verdict, dated March 9, 2015, ruling in favor of the Plaintiff and awarding it \$5,463, plus interest. We believe we have grounds to move for a new trial as well as grounds to appeal this decision and are evaluating both options. We expect to file a motion requesting a new trial or a notice of appeal in the next few weeks. 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 settlement with the Plaintiffs under which the Plaintiffs agreed to dismiss the lawsuit with prejudice in exchange for a settlement payment of \$2,950, which was within the remaining policy limits of our director and officer insurance policy. The final settlement was approved by the court, and the case was dismissed with prejudice, as of February 3, 2015, subsequent to the end of the Company's third fiscal quarter.

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

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(Unaudited)

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

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 believed it had 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 nine months ended January 31, 2015. 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. A mediation was held on February 24, 2015, subsequent to the end of our third fiscal quarter. 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

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MILLER ENERGY RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(Unaudited)

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

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. Pursuant to a motion from Plains Capital Bank, the case was transferred to Texas. We filed a motion to dismiss the case against the Company on October 9, 2014, which was granted on January 22, 2015. The court did, however, give Vulcan 30 days to replead their concert of action/civil conspiracy claim. An amended complaint as to this cause of action was filed on February 23, 2015. We are currently drafting a responsive pleading. In addition, we note that 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

Payment of Dividends

The following table summarizes the Series B Preferred Stock, Series C Preferred Stock and Series D Preferred Stock dividend activity subsequent to January 31, 2015.

| Series | Declaration Date | Dividend Paid per Share | Annualized Percentage Rate | Par Value | Accrual Period | Record Date | Payment Date |
|--------|------------------|-------------------------|----------------------------|-----------|-------------------------------|-------------------|---------------|
| B | January 30, 2015 | \$5.95 | 12 % | \$100.00 | Sept. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |
| C | January 30, 2015 | \$0.67 | 10.75 % | \$25.00 | Dec. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |
| D | January 30, 2015 | \$0.66 | 10.5 % | \$25.00 | Dec. 1, 2014 - Feb. 28, 2015 | February 13, 2015 | March 2, 2015 |

First Lien RBL Amendment

On March 11, 2015, the Company entered into a Waiver and Fourth Amendment to Credit Agreement and Second Amendment to Guarantee and Collateral Agreement (the "March 2015 First Lien Amendment") to the First Lien RBL. The March 2015 First Lien Amendment, among other things, (i) allows us 60 days from the date of the March 2015 First Lien Amendment to provide a mortgage to the RBL Lenders covering the North Fork Pipeline and 30 days from that date to have Savant deliver a mortgage in favor of the RBL Lenders covering its oil and gas properties, (ii) adds a requirement that we engage a field auditor and complete a review of our accounts payable, (iii) requires that we deliver to the RBL Administrative Agent an engineering report on or before May 1, 2015 which will serve as the basis of an interim redetermination of the borrowing base under the First Lien Loan Agreement, which will be permitted in addition to the other redeterminations otherwise permitted under the First Lien Loan Agreement, (iv) sets new minimum liquidity requirements, (v) amends APOD A and certain defined terms, (vi) requires that we apply certain expected tax credit receipts to pay down the outstanding balance of the loans outstanding under the First Lien Loan Agreement, (vii) amends restrictions on minimum availability that must be maintained under the First Lien Loan Agreement, includes additional restrictions on capital expenditures, (viii) permits us to issue an additional \$50,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of \$100,000 and requires that we raise at least \$10,000 of net cash proceeds from the issuance of preferred equity interests on or before

April 30, 2015, (ix) amends the borrowing base to \$45,000 for the period beginning on the date of the March 2015 First Lien Amendment until the next redetermination date, (x) amends and updates a list of pledged equity interests attached as Schedule 2 to the associated Guarantee and Collateral Agreement in favor of the RBL Lenders, (xi) by an amendment to the definition of "Applicable Margin," increases the interest rates payable on the loans outstanding under the First Lien RBL by 1.0%, as compared to the interest rates payable prior to the date of the March 2015 First Lien Amendment, and (xii) provides waivers related to certain events of default resulting from (A) the impairment of our proved reserves, (B) our issuance of preferred equity interests with a stated liquidation preference in excess of \$50,000, (C) the existence of debt in the form of accounts payable that were greater than 90 days past due, (D) our failure to provide an executed mortgage and related legal opinions on the North Fork Pipeline when due pursuant to a prior amendment, (E) our payment of dividends on our preferred stock while an event of default existed under the First Lien Loan Agreement, and (F) related cross defaults arising under the Second Lien Credit Facility.

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MILLER ENERGY RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(Unaudited)

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

Second Lien Amendment

On March 11, 2015, the Company entered into a Waiver and Amendment No. 5 to Credit Agreement and Amendment No. 3 to Guarantee and Collateral Agreement (the "March 2015 Second Lien Amendment") to the Second Lien Credit Agreement. The March 2015 Second Lien Amendment, among other things, (i) allows us 60 days from the date of the 2015 Second Lien Amendment to provide a mortgage to the Second Lien Lenders covering the North Fork Pipeline and 30 days from that date to have Savant deliver a mortgage in favor of the Second Lien Lenders covering its oil and gas properties, (ii) adds a requirement that we engage a field auditor and complete a review of our accounts payable, (iii) requires that we deliver to the Second Lien Agent an engineering report on or before May 1, 2015, (iv) amends the provision on "additional interest" to require that we pay an additional 1.0% interest in cash plus 2.0% interest in kind on the loans outstanding under the Second Lien Credit Agreement (subject to future reductions of the additional interest payable in kind if certain operational and capital expenditure conditions are met by May 31, 2015), (v) amends APOD A and certain defined terms, (vi) includes additional restrictions on capital expenditures, (vii) permits us to issue an additional \$50,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of \$100,000 in stated liquidation preference) and requires that we raise at least \$10,000 of net cash proceeds from the issuance of preferred equity interests on or before April 30, 2015, (viii) amends and updates a list of pledged equity interests attached as Schedule 2 to the associated Guarantee and Collateral Agreement in favor of the Second Lien Lenders, and (ix) provides waivers related to certain events of default resulting from (A) the impairment of our proved reserves, (B) our issuance of preferred equity interests with a stated liquidation preference in excess of \$50,000, (C) the existence of debt in the form of accounts payable that are greater than 90 days past due, (D) our failure to provide an executed mortgage and related legal opinions on the North Fork Pipeline pursuant to a prior amendment, (E) our payment of dividends on our preferred stock while an Event of Default existed, and (F) related cross defaults arising under the First Lien Credit Facility.

Verdict in VAI, Inc. v Miller Energy Resources Litigation

As describe more fully in Note 15 - Litigation, 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. Following a bench trial, we received a verdict in this case, dated March 9, 2015, ruling in favor of the Plaintiff and awarding it \$5,463, plus interest. We believe we have grounds to move for a new trial as well as grounds to appeal this decision and are evaluating both options. We expect to file a motion requesting a new trial or a notice of appeal in the next few weeks. 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.

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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. During fiscal 2015, we expanded our operations to the North Slope through acquiring the Badami field and pipeline system, and wrapped up our operations in Tennessee by divesting those assets.

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 Alaska 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 Alaska 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.

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(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 third quarter of fiscal 2015. For the nine-month period ended January 31, 2015, 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, as amended on December 11, 2014, with Savant, subject to due diligence and regulatory approval, for \$9,000. We acquired 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 acquired certain midstream assets located on the North Slope. We announced the close of the acquisition on December 12, 2014.

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. Rig 37 was used to drill NFU 24-26.

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 our 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.

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, 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

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

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.

During the nine months ended January 31, 2015, we closed on the sale of substantially all of our Tennessee oil and gas properties, including our oil and gas inventory, yielding proceeds of \$4,191 in cash. 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.

On December 11, 2014, we closed on the acquisition of Savant for approximately \$6,000 in cash, and issued three promissory notes at \$1,000 each. As a result of this merger, we acquired a 67.5% working interest in the Badami Unit, 100% ownership in certain nearby leases, and certain midstream assets located in the North Slope. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. This acquisition immediately added approximately 600 bopd net to our production.

During the nine months ended January 31, 2015, we recorded a charge to exploration expense of \$18,800 for Olson Creek #2, which was determined to be a dry hole.

On January 31, 2015, the significant and continued decline in crude oil prices during the third quarter of fiscal 2015 was identified as an impairment-related triggering event for proved properties. The Redoubt Unit and West McArthur River 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 and the West McArthur River Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved and unproved properties of the Redoubt Unit and West McArthur River Unit of \$81,480 and \$67,586, respectively. Continuing crude oil price declines and the results of drilling efforts or changes in reserve estimates could trigger future impairments. Additionally, the significant decline in oil prices led to changes in our drilling plans, which resulted in an impairment of unproved properties of \$34,967 during the three months ended January 31, 2015.

On February 10, 2015, we received proceeds from Alaska State tax credits totaling \$21,204.

On February 12, 2015, we entered into a binding agreement to sell our Hawker Siddeley aircraft and related equipment for \$150 in cash.

On March 3, 2015, we announced that we had successfully drilled and completed our first two new gas wells at the North Fork unit, bringing both onto production. The first well, NF 24-26, currently producing at a rate of approximately 1,650 Mcfd. The second well, NF 42-35, is currently producing at a rate of approximately 350 Mcfd and continues to increase as drilling fluids diminish.

On March 11, 2015, we amended our First Lien Credit Facility and Second Lien Credit Facility to waive certain events of default that existed as of January 31, 2015, among other things.

Outlook

As we head into the final quarter of fiscal 2015, due to the decline in oil, we are reducing our overall level of capital expenditures given our need to ensure sufficient liquidity as well as to reduce our leverage. We are currently evaluating lower-risk work over opportunities at our North Fork unit in addition to two new wells. Capital expenditures for the remainder of calendar 2015, including final quarter of fiscal 2015, should be less than \$40,000. Additionally, at Redoubt, we plan on drilling a lower-risk sidetrack at RU-7.

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

Results of Operations

Three Months Ended January 31, 2015 Compared to Three Months Ended January 31, 2014

Revenues

| | For the Three Months Ended January 31, | | | |
|--------------------|--|-----------|-------------|------------|
| | 2015 | 2014 | \$ Variance | % Variance |
| Oil sales: | | | | |
| Alaska region | \$ 14,952 | \$ 15,717 | \$(765) | (5)% |
| Appalachian region | 1 | 631 | (630) | (100) |
| Total | \$ 14,953 | \$ 16,348 | (1,395) | (9) |
| Natural gas sales: | | | | |
| Alaska region | \$ 4,767 | \$ 28 | 4,739 | 16,925 |
| Appalachian region | 1 | 90 | (89) | (99) |
| Total | \$ 4,768 | \$ 118 | 4,650 | 3,941 |
| Other: | | | | |
| Alaska region | \$ 523 | \$ 7 | 516 | 7,371 |
| Appalachian region | 27 | 155 | (128) | (83) |
| Total | \$ 550 | \$ 162 | 388 | 240 |
| Total revenues | \$ 20,271 | \$ 16,628 | \$ 3,643 | 22% |

Net Production

| | For the Three Months Ended January 31, | | | |
|--|--|---------|----------|------------|
| | 2015 | 2014 | Variance | % Variance |
| Oil volume - bbls: | | | | |
| Alaska region | 220,781 | 212,441 | 8,340 | 4% |
| Appalachian region | 181 | 6,981 | (6,800) | (97) |
| Total | 220,962 | 219,422 | 1,540 | 1 |
| Natural gas volume ¹ - mcf: | | | | |
| Alaska region | 550,997 | 5,277 | 545,720 | 10,341 |
| Appalachian region | 515 | 30,450 | (29,935) | (98) |
| Total | 551,512 | 35,727 | 515,785 | 1,444 |
| Total production ² - boe: | | | | |
| Alaska region | 312,614 | 213,321 | 99,293 | 47 |
| Appalachian region | 267 | 12,056 | (11,789) | (98) |
| Total | 312,881 | 225,377 | 87,504 | 39% |

¹ Alaska 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.

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

Pricing

| | For the Three Months Ended | | | |
|---|----------------------------|---------|-------------|------------|
| | January 31, 2015 | 2014 | \$ Variance | % Variance |
| Average realized oil sales price - per barrel: | | | | |
| Alaska region | \$59.32 | \$94.75 | \$(35.43) | (37)% |
| Appalachian region | 64.38 | 90.39 | (26.01) | (29) |
| Total | \$57.26 | \$94.58 | \$(37.32) | (39) |
| Average realized natural gas sales price - per mcf: | | | | |
| Alaska region | \$6.43 | \$5.24 | \$1.19 | 23 |
| Appalachian region | 2.19 | 3.06 | (0.87) | (28) |
| Total | \$6.42 | \$3.39 | \$3.03 | 89% |

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 third quarter of 2015 were 39% below the same period last year. For the three months ended January 31, 2015, realized oil prices averaged \$57.26 per bbl, compared with \$94.58 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 third quarter of fiscal 2015 increased over the same period last year. For the three months ended January 31, 2015, realized natural gas prices averaged \$6.42 per mcf, compared with \$3.39 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 third quarter of fiscal 2015, oil revenues totaled \$14,953, which represents a 9% decrease over the same period in the prior year. Oil revenues represented 74% of our third quarter consolidated total revenues. Net barrels sold for the current period were 261,190, which represents an 88,334 bbl, or 51%, increase as compared to the same period last year. The increase in barrels sold was more than offset by a 39% decrease in realized oil prices. The increase in net barrels sold results from an increase in oil shipments. Additionally, oil production increased 1,540 bbls, or 1%, to 220,962 bbls. The increase was driven by an 8,340 bbl increase in the Alaska region offset by a 6,800 bbl decrease in the Appalachian region. The production increase in the Alaska region resulted from a new well being brought online, WMRU-2B in our West McArthur River Unit field, and the acquisition of Savant.

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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 Alaska 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 decreased during the third quarter of fiscal 2015 due to the timing of shipment schedules.

| | For the Three Months Ended January 31, 2015 | | |
|--|---|-------------|-----------|
| | Alaska | Appalachian | Total |
| In barrels: | | | |
| Beginning inventory balance | 100,400 | 9,807 | 110,207 |
| Addition to inventory - gross production | 256,654 | 181 | 256,835 |
| Reduction to inventory - gross sales | (306,070) | (75) | (306,145) |
| Reduction to inventory - Tennessee assets sold | — | (9,570) | (9,570) |
| Pipeline adjustments | (214) | — | (214) |
| Ending inventory balance | 50,770 | 343 | 51,113 |
| Net change in inventory | (49,630) | (9,464) | (59,094) |

Natural Gas Sales

During the third quarter of fiscal 2015, natural gas revenues totaled \$4,768, which was \$4,650 higher than the same period in the prior year. The increase resulted from a combination of an 89% increase in average realized prices and a 1,444% increase in production. The higher realized average prices primarily resulted 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. Natural gas represented 24% of our third quarter consolidated total revenues.

Other

Other revenues primarily represent revenues generated from pipeline tariff fees, 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 Alaska region. During the third quarters of fiscal 2015 and 2014, other revenues totaled \$550 and \$162, respectively.

Cost and Expenses

The table below presents a comparison of our expenses for the three months ended January 31, 2015 and 2014:

| | For the Three Months Ended | | | |
|---|----------------------------|----------|-------------|------------|
| | January 31, | | | |
| | 2015 | 2014 | \$ Variance | % Variance |
| Lease operating expense | \$8,803 | \$4,410 | \$4,393 | 100 % |
| Transportation costs | 1,607 | 1,411 | 196 | 14 |
| Cost of purchased gas sold | 316 | — | 316 | N/A |
| Cost of other revenue | 640 | 256 | 384 | 150 |
| General and administrative | 7,358 | 7,587 | (229) | (3) |
| Alaska carried-forward annual loss credits, net | (21,508) | — | (21,508) | N/A |
| Exploration expense | 77,740 | 352 | 77,388 | 21,985 |
| Depreciation, depletion and amortization | 19,541 | 7,642 | 11,899 | 156 |
| Accretion of asset retirement obligation | 370 | 305 | 65 | 21 |
| Impairment of proved properties and other long lived assets | 117,037 | — | 117,037 | N/A |
| Other operating expense, net | 900 | 1,250 | \$(350) | (28) |
| Total operating expense | \$212,804 | \$23,213 | \$189,591 | 817 % |

N/A = not applicable

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(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 January 31, 2015 and 2014:

| | For the Three Months Ended | | | | |
|--|----------------------------|---------|-------------|------------|--|
| | January 31, | | \$ Variance | % Variance | |
| | 2015 | 2014 | | | |
| Lease operating expense | \$8,803 | \$4,410 | \$4,393 | 100 | |
| Net production - boe | 312,881 | 225,377 | | | |
| Lease operating expense per boe produced | \$28.14 | \$19.57 | | | |

Lease operating expense increased \$4,393 from fiscal 2014, or 100%. The increased lease operating expense is primarily attributable to increased production, high operating expenses at the Badami Unit attributable to the acquisition of Savant, and costs allocated to lease operating expense due to changes in inventory and lower of cost of market adjustments which negatively impacted lease operating expenses by \$1,470 for the three months ended January 31, 2015. For the third quarter of fiscal 2015, our lease operating expense per boe produced was \$28.14 as compared to \$19.57 for the third quarter of fiscal 2014. We expect our lease operating expense per boe produced to decline as increased production creates marginal increases in labor and camp facility costs and well maintenance; however, the majority of our production costs are fixed.

Transportation Costs

Transportation costs increased \$196 from fiscal 2014, or 14%, due to transportation costs associated with natural gas marketing sales.

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 \$316 in purchased gas costs during the third quarter of fiscal 2015 and none during the third 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 costs to operate the pipeline assets located in the North Slope, 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 | | | | |
|---------------------|----------------------------|-------|-------------|------------|----|
| | January 31, | | \$ Variance | % Variance | |
| | 2015 | 2014 | | | |
| Pipeline operations | \$466 | \$— | \$466 | N/A | |
| Direct labor | 130 | 153 | (23 |) (15 |)% |
| Equipment | 9 | 24 | (15 |) (63 |) |
| Repairs | 26 | 67 | (41 |) (61 |) |
| Other | 9 | 12 | (3 |) (25 |) |
| Total | \$640 | \$256 | \$384 | 150 | % |

N/A = not applicable

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(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 | | | |
|--------------------------|----------------------------|---------|-------------|------------|
| | January 31, | | | |
| | 2015 | 2014 | \$ Variance | % Variance |
| Stock-based compensation | \$728 | \$1,440 | \$(712) | (49)% |
| Professional fees | 2,803 | 2,768 | 35 | 1 |
| Salaries | 1,649 | 1,551 | 98 | 6 |
| Travel | 299 | 502 | (203) | (40) |
| Employee benefits | 489 | 609 | (120) | (20) |
| Other | 1,390 | 717 | 673 | 94 |
| Total | \$7,358 | \$7,587 | \$(229) | (3)% |

G&A expenses decreased \$229 from fiscal 2014, or 3% from the same period in the prior fiscal year. Salaries increased 6% from the same period in the prior fiscal year primarily due to an increase in staff.

Exploration Expense

Exploration expense incurred increased \$77,388 from fiscal 2014. 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 third quarter of 2015, we wrote off additional costs related to exploratory well Olson Creek #2 resulting in a charge of \$5,475, and \$36,234 of unproved property costs of the Redoubt Unit and West McArthur River Unit. Additionally, during the fiscal third quarter of 2015, we wrote off \$34,967 due to the abandonment associated with certain leases of unproved properties due to changes in our drilling plans and incurred \$972 in delay rentals.

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 | | | |
|--------------------|----------------------------|---------|-------------|------------|
| | January 31, | | | |
| | 2015 | 2014 | \$ Variance | % Variance |
| Depletion: | | | | |
| Alaska region | \$18,213 | \$6,411 | \$11,802 | 184% |
| Appalachian region | 1 | 215 | (214) | (100)% |
| | 18,214 | 6,626 | 11,588 | 175 |
| Depreciation: | | | | |
| Alaska region | 1,214 | 832 | 382 | 46 |
| Appalachian region | 113 | 184 | (71) | (39) |
| | 1,327 | 1,016 | 311 | 31 |
| Total DD&A | \$19,541 | \$7,642 | \$11,899 | 156% |

The increase in DD&A expense is primarily a result of 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 21% to \$370 primarily due to additions to asset retirement obligations over the trailing twelve months related to acquisitions and long lived assets.

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

Impairment of Proved Properties and Other Long-Lived Assets

On January 31, 2015, the significant and continued decline in crude oil prices during the third quarter of fiscal 2015 was identified as an impairment related triggering event for proved properties. The Redoubt Unit and West McArthur River 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 and the West McArthur River Unit based on discounted cash flows. The step 2 analysis resulted in an impairment to proved properties of \$45,781 related to the Redoubt Unit and an impairment of \$67,051 related to the West McArthur River Unit.

In addition, during the fiscal third quarter, we recognized an impairment of \$4,205 to write down certain Tennessee related assets classified as held for sale as of January 31, 2015 that remained subsequent to the sale of substantially all of our Tennessee oil and gas properties to reflect the expected respective sales price of those assets.

Other Income and Expense

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

| | For the Three Months Ended | | | | |
|--------------------------|----------------------------|----------|-------------|------------|---|
| | January 31, | | \$ Variance | % Variance | |
| | 2015 | 2014 | | | |
| Interest expense, net | \$(2,478 |) \$(407 |) \$(2,071 |) 509 | % |
| Gain on derivatives, net | 39,330 | 1,677 | 37,653 | 2,245 | |
| Other income, net | 404 | 42 | 362 | (862 |) |
| Total | \$37,256 | \$1,312 | \$35,944 | 2,740 | % |

Interest Expense, Net

Interest expense, net, increased \$2,071 from fiscal 2014, or 509%. 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 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 \$37,653 during the three months ended January 31, 2015 compared to the three months ended January 31, 2014. Of the total change, \$8,154 was due to a favorable change in realized cash settlements related to our derivative positions in the three months ended January 31, 2015 compared to the three months ended January 31, 2014. 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 \$845 from fiscal 2014, or 39%, due to an increase in loss before income taxes. Our effective income tax rate for the third quarter of fiscal 2015 was 2%. 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 changes in our valuation allowance against our state and federal operating loss carry-forwards and credits.

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

Results of Operations

Nine Months Ended January 31, 2015 Compared to Nine Months Ended January 31, 2014

Revenues

| | For the Nine Months Ended January 31, | | | | |
|--------------------|---------------------------------------|----------|-------------|------------|---|
| | 2015 | 2014 | \$ Variance | % Variance | |
| Oil sales: | | | | | |
| Alaska region | \$51,092 | \$45,117 | \$5,975 | 13 | % |
| Appalachian region | 1,206 | 1,895 | (689) | (36) |) |
| Total | \$52,298 | \$47,012 | 5,286 | 11 | |
| Natural gas sales: | | | | | |
| Alaska region | \$16,142 | \$380 | 15,762 | 4,148 | |
| Appalachian region | 288 | 291 | (3) | (1) |) |
| Total | \$16,430 | \$671 | 15,759 | 2,349 | |
| Other: | | | | | |
| Alaska region | \$643 | \$141 | 502 | 356 | |
| Appalachian region | 455 | 608 | (153) | (25) |) |
| Total | \$1,098 | \$749 | 349 | 47 | |
| Total revenues | \$69,826 | \$48,432 | \$21,394 | 44 | % |

Net Production

| | For the Nine Months Ended January 31, | | | | |
|--|---------------------------------------|---------|-----------|------------|---|
| | 2015 | 2014 | Variance | % Variance | |
| Oil volume - bbls: | | | | | |
| Alaska region | 625,191 | 496,349 | 128,842 | 26 | % |
| Appalachian region | 12,136 | 19,789 | (7,653) | (39) |) |
| Total | 637,327 | 516,138 | 121,189 | 23 | |
| Natural gas volume ¹ - mcf: | | | | | |
| Alaska region | 1,615,325 | 77,928 | 1,537,397 | 1,973 | |
| Appalachian region | 73,269 | 87,547 | (14,278) | (16) |) |
| Total | 1,688,594 | 165,475 | 1,523,119 | 920 | |
| Total production ² - boe: | | | | | |
| Alaska region | 894,412 | 509,337 | 385,075 | 76 | |
| Appalachian region | 24,348 | 34,380 | (10,032) | (29) |) |
| Total | 918,760 | 543,717 | 375,043 | 69 | % |

¹ Alaska 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.

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

Pricing

| | For the Nine Months Ended January | | | |
|---|-----------------------------------|----------|-------------|------------|
| | 31, | | | |
| | 2015 | 2014 | \$ Variance | % Variance |
| Average realized oil sales price - per barrel: | | | | |
| Alaska region | \$80.98 | \$100.49 | \$(19.51) | (19)% |
| Appalachian region | 92.23 | 92.83 | (0.60) | (1) |
| Total | \$79.23 | \$100.16 | \$(20.93) | (21) |
| Average realized natural gas sales price - per mcf: | | | | |
| Alaska region | \$6.76 | \$4.88 | \$1.88 | 39 |
| Appalachian region | 3.92 | 3.32 | 0.60 | 18 |
| Total | \$6.68 | \$4.06 | \$2.62 | 65% |

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 nine months of 2015 were 21% below the same period last year. For the nine months ended January 31, 2015, realized oil prices averaged \$79.23 per bbl, compared with \$100.16 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 nine months ended January 31, 2015 were higher over the same period last year. For the nine months ended January 31, 2015, realized natural gas prices averaged \$6.68 per mcf, compared with \$4.06 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 nine months ended of fiscal 2015, oil revenues totaled \$52,298, which represents an 11% increase over the same period in the prior year. Oil revenues represented 75% of our nine months ended January 31, 2015 consolidated total revenues. Net barrels sold for the current period were 660,096, which represents a 190,709 bbl, or 41%, increase as compared to the same period last year. The increase in barrels sold was partially offset by a 21% decrease in realized oil prices.

The increase in net barrels sold resulted from an increase in oil production for the period. Oil production increased 121,189 bbls, or 23%, to 637,327 bbls. The increase was driven by a 128,842 bbl increase in the Alaska region offset by a 7,653 bbl decrease in the Appalachian region. The production increase in the Alaska region resulted from new wells being brought online, including WMRU-8, WMRU-2B, and Sword #1 in our West McArthur River Unit field, the acquisition of Savant, and RU-5B in our Redoubt Shoals field.

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(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 Alaska 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 a decline in inventory levels during the first nine months of fiscal 2015 due to timing of shipping schedules.

| | For the Nine Months Ended January 31, 2015 | | |
|--|--|-------------|------------|
| | Alaska | Appalachian | Total |
| In barrels: | | | |
| Beginning inventory balance | 82,495 | 10,895 | 93,390 |
| Addition to inventory - gross production | 738,668 | 12,136 | 750,804 |
| Reduction to inventory - gross sales | (768,774 |) (13,118 |) (781,892 |
| Reduction to inventory - Tennessee assets sold | — | (9,570 |) (9,570 |
| Pipeline adjustments | (1,619 |) — | (1,619 |
| Ending inventory balance | 50,770 | 343 | 51,113 |
| Net change in inventory | (31,725 |) (10,552 |) (42,277 |

Natural Gas Sales

During the first nine months of fiscal 2015, natural gas revenues totaled \$16,430, which was \$15,759 higher than the same period in the prior year. The increase resulted from a combination of a 65% increase in average realized prices and a 920% increase in production. The higher realized average prices primarily resulted 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. Natural gas represented 24% of our nine months consolidated total revenues.

Other

Other revenues primarily represent revenues generated from pipeline tariff fees, 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 Alaska region. During the first nine months of fiscal 2015 and 2014, other revenues totaled \$1,098 and \$749, respectively.

Cost and Expenses

The table below presents a comparison of our expenses for the nine months ended January 31, 2015 and 2014:

| | For the Nine Months Ended January | | | | |
|---|-----------------------------------|----------|-------------|------------|---|
| | 2015 | 2014 | \$ Variance | % Variance | |
| Lease operating expense | \$24,392 | \$15,226 | \$9,166 | 60 | % |
| Transportation costs | 4,149 | 3,023 | 1,126 | 37 | |
| Cost of purchased gas sold | 2,572 | — | 2,572 | N/A | |
| Cost of other revenue | 1,305 | 844 | 461 | 55 | |
| General and administrative | 34,770 | 21,092 | 13,678 | 65 | |
| Alaska carried-forward annual loss credits, net | (24,240 |) — | (24,240 |) N/A | |
| Exploration expense | 244,848 | 786 | 244,062 | 31,051 | |
| Depreciation, depletion and amortization | 56,601 | 22,352 | 34,249 | 153 | |
| Accretion of asset retirement obligation | 1,067 | 903 | 164 | 18 | |
| Impairment of proved properties and other long lived assets | 230,771 | — | 230,771 | N/A | |
| Other operating expense, net | 904 | 1,250 | (346 |) (28 |) |
| Total operating expense | \$577,139 | \$65,476 | \$511,663 | 781 | % |

N/A = not applicable

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(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 nine months ended January 31, 2015 and 2014:

| | For the Nine Months Ended January | | | | |
|--|-----------------------------------|----------|-------------|------------|---|
| | 31, | | | | |
| | 2015 | 2014 | \$ Variance | % Variance | |
| Lease operating expense | \$24,392 | \$15,226 | \$9,166 | 60 | % |
| Net production - boe | 918,760 | 543,717 | | | |
| Lease operating expense per boe produced | \$26.55 | \$28.00 | | | |

Lease operating expense increased 60% from the first nine months of fiscal 2014, or \$9,166. The increased lease operating expense is primarily attributable to increased production and costs allocated to lease operating expense due to changes in inventory and a lower of cost or market adjustment to inventory which negatively impacted our lease operating expenses by \$1,752 during the first nine months of fiscal 2015. For the nine months ended January 31, 2015, our lease operating expense per boe produced was \$26.55 as compared to \$28.00 for the same period in the prior fiscal year. We expect our lease operating expense per boe produced to decline as increased production creates marginal increases in labor and camp facility costs and well maintenance; however, the majority of our production costs are fixed.

Transportation Costs

Transportation costs increased \$1,126 from the first nine months of fiscal 2014, or 37%, due to increased oil production and increased gas transportation costs.

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 \$2,572 in purchased gas costs during the first nine months of fiscal 2015 and none during the first nine 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 Nine Months Ended January | | | | |
|---------------------|-----------------------------------|-------|-------------|------------|---|
| | 31, | | | | |
| | 2015 | 2014 | \$ Variance | % Variance | |
| Pipeline operations | \$466 | \$— | \$466 | N/A | |
| Direct labor | 587 | 458 | 129 | 28 | % |
| Equipment | 68 | 99 | (31) | (31) |) |
| Repairs | 159 | 253 | (94) | (37) |) |
| Other | 25 | 34 | (9) | (26) |) |
| Total | \$1,305 | \$844 | \$461 | 55 | % |

N/A = not applicable

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(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 Nine Months Ended January 31, | | | | |
|--------------------------|---------------------------------------|-----------|-------------|------------|---|
| | 2015 | 2014 | \$ Variance | % Variance | |
| Stock-based compensation | \$ 10,794 | \$ 4,820 | \$ 5,974 | 124 | % |
| Professional fees | 10,032 | 6,920 | 3,112 | 45 | |
| Salaries | 8,200 | 3,927 | 4,273 | 109 | |
| Travel | 1,231 | 1,488 | (257) | (17) |) |
| Employee benefits | 1,174 | 1,433 | (259) | (18) |) |
| Other | 3,339 | 2,504 | 835 | 33 | |
| Total | \$ 34,770 | \$ 21,092 | \$ 13,678 | 65 | % |

G&A expenses increased \$13,678 from the nine months ended January 31, 2015, or 65%. Salaries increased 109% 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 124% due to recent grants to directors and key employees.

Exploration Expense

Exploration expense increased \$244,062 from the nine months ended January 31, 2015, or 31,051%. 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 nine months of fiscal 2015, we wrote off exploratory well Olson Creek #2 resulting in a charge of \$18,800 including unproved leasehold costs, net of tax credits, \$188,586 of unproved property costs of the Redoubt Unit, and \$535 of unproved property costs of the West McArthur River Unit. Also during the first nine months of fiscal 2015, we wrote off other unproved properties, including exploratory well Olson Creek #1 and Otter #1 resulting in a charge of \$35,059, due to changes in our drilling plans and incurred \$1,867 in delay rentals.

Depreciation, Depletion and Amortization

DD&A expenses include the DD&A of leasehold costs and equipment of leasehold costs and equipment. Depletion is calculated on a unit-of-production basis. Depreciation is calculated on a straight-line basis.

| | For the Nine Months Ended January 31, | | | | |
|--------------------|---------------------------------------|-----------|-------------|------------|---|
| | 2015 | 2014 | \$ Variance | % Variance | |
| Depletion: | | | | | |
| Alaska region | \$ 52,481 | \$ 18,405 | \$ 34,076 | 185 | % |
| Appalachian region | 759 | 753 | 6 | 1 | |
| | 53,240 | 19,158 | 34,082 | 178 | |
| Depreciation: | | | | | |
| Alaska region | 2,936 | 2,646 | 290 | 11 | |
| Appalachian region | 425 | 548 | (123) | (22) |) |
| | 3,361 | 3,194 | 167 | 5 | |
| Total DD&A | \$ 56,601 | \$ 22,352 | \$ 34,249 | 153 | % |

The increase in DD&A expense is primarily a result of increased production from the Alaska 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 18% to \$164 primarily due to additions to asset retirement

obligations.

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

Impairment of Proved Properties and Other Long-Lived Assets

On October 31, 2014 and again on January 31, 2015, the significant and continued decline in crude oil prices during the second and third quarters of fiscal 2015 were identified as impairment related triggering events for proved properties. The Redoubt Unit and West McArthur River 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 and the West McArthur River Unit based on discounted cash flows. The step 2 analyses resulted in a year to date impairment to proved properties of \$158,196 related to the Redoubt Unit and an impairment of \$67,051 related to the West McArthur River Unit.

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. During the fiscal third quarter, we recognized an impairment of \$4,205 to write down certain Tennessee related assets classified as held for sale as of January 31, 2015 that remained subsequent to the sale of substantially all of our Tennessee oil and gas properties to reflect the expected respective sales price of those assets.

Other Income and Expense

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

| | For the Nine Months Ended January 31, | | | | |
|---------------------------------|---------------------------------------|------------|-------------|------------|----|
| | 2015 | 2014 | \$ Variance | % Variance | |
| Interest expense, net | \$(8,896 |) \$(4,051 |) \$(4,845 |) 120 | % |
| Gain (loss) on derivatives, net | 55,516 | (5,589 |) 61,105 | (1,093 |) |
| Other income, net | 559 | 26 | 533 | (2,050 |) |
| Total | \$47,179 | \$ (9,614 |) \$56,793 | (591 |)% |

Interest Expense, Net

Interest expense, net, increased \$4,845 during the nine months ended January 31, 2015, or 120%. 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 \$61,105 during the nine months ended January 31, 2015 compared to the nine months ended January 31, 2014. Of the total change, \$9,534 was due to a favorable change in realized cash settlements related to our derivative positions in the nine months ended January 31, 2015 compared to the nine months ended January 31, 2014. 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 \$116,471 during the nine months ended January 31, 2015, or 1,001% due to an increase in loss before income taxes. Our effective income tax rate for the first nine months of fiscal 2015 was 28%. 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 changes in our valuation allowance against our state and federal deferred tax assets.

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,

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

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, and to supplemental risk factors included in our Quarterly Reports filed during fiscal 2015.

For the three and nine months ended January 31, 2015, we experienced an operating loss. We anticipate that our operating expenses will continue to increase as we fully develop our assets in the Alaska 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.

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. On December 11, 2014, we drew \$3,000 down and an additional \$5,000 on December 31, 2014. The remaining availability under the First Lien RBL was \$6,000 as of January 31, 2015. 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 nine months ended January 31, 2015, we entered into a capital lease for the newly purchased Rig 36 and certain modifications and improvements made to it, 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, the Company entered into the December First Lien Amendment to our First Lien Loan Agreement. The December First Lien Amendment, among other things, (1) amends our leverage and interest covenants, (2) establishes the Plans, defines "Permitted Capital Expenditures," adds requirements for the development of our drilling program within those Plans and restricts our ability to engage in capital expenditures other than Permitted Capital Expenditures, in each case in a manner consistent with the December Second Lien Amendment, (3) permits us to issue an additional \$25,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (up to \$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 RBL Administrative Agent (for the benefit of the RBL 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 RBL 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 RBL Lenders to exceed \$50,000 in the aggregate prior to next redetermination date for our borrowing base, scheduled for February 1, 2015 and (11) required that, following receipt of our tax credit payment from the State of Alaska in February of 2015, we not allow the aggregate revolving credit exposure of the RBL Lenders to exceed \$40,000.

On December 10, 2014, the Company entered into the December Second Lien Amendment to our Second Lien Credit Agreement. The December Second Lien Amendment, among other things, (1) makes conforming amendments to our leverage

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

and interest covenants, matching those in the December First Lien Amendment (as defined below), (2) establishes approved plans of development (the "Plans"), defines "Permitted Capital Expenditures," 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 (as with the December First Lien Amendment, up to \$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 the December 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 the 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). and the December Second Lien Amendment.

On February 10, 2015, we received the proceeds of Alaska production credits totaling \$21,204 from the State of Alaska and repaid \$5,000 on the First Lien RBL.

On March 11, 2015, the Company entered into a Waiver and Fourth Amendment to Credit Agreement and Second Amendment to Guarantee and Collateral Agreement (the "March 2015 First Lien Amendment") to the First Lien RBL. The March 2015 First Lien Amendment, among other things, (i) allows us 60 days from the date of the March 2015 First Lien Amendment to provide a mortgage to the RBL Lenders covering the North Fork Pipeline and 30 days from that date to have Savant deliver a mortgage in favor of the RBL Lenders covering its oil and gas properties, (ii) adds a requirement that we engage a field auditor and complete a review of our accounts payable, (iii) requires that we deliver to the RBL Administrative Agent an engineering report on or before May 1, 2015 which will serve as the basis of an interim redetermination of the borrowing base under the First Lien Loan Agreement, which will be permitted in addition to the other redeterminations otherwise permitted under the First Lien Loan Agreement, (iv) sets new minimum liquidity requirements, (v) amends APOD A and certain defined terms, (vi) requires that we apply certain expected tax credit receipts to pay down the outstanding balance of the loans outstanding under the First Lien Loan Agreement, (vii) amends restrictions on minimum availability that must be maintained under the First Lien Loan Agreement, includes additional restrictions on capital expenditures, (viii) permits us to issue an additional \$50,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of \$100,000 and requires that we raise at least \$10,000 of net cash proceeds from the issuance of preferred equity interests on or before April 30, 2015, (ix) amends the borrowing base to \$45,000 for the period beginning on the date of the March 2015 First Lien Amendment until the next redetermination date, (x) amends and updates a list of pledged equity interests attached as Schedule 2 to the associated Guarantee and Collateral Agreement in favor of the RBL Lenders, (xi) by an amendment to the definition of "Applicable Margin," increases the interest rates payable on the loans outstanding under the First Lien RBL by 1.0%, as compared to the interest rates payable prior to the date of the March 2015 First Lien Amendment, and (xii) provides waivers related to certain events of default resulting from (A) the impairment of

our proved reserves, (B) our issuance of preferred equity interests with a stated liquidation preference in excess of \$50,000, (C) the existence of debt in the form of accounts payable that were greater than 90 days past due, (D) our failure to provide an executed mortgage and related legal opinions on the North Fork Pipeline when due pursuant to a prior amendment, (E) our payment of dividends on our preferred stock while an event of default existed under the First Lien Loan Agreement, and (F) related cross defaults arising under the Second Lien Credit Facility.

On March 11, 2015, the Company entered into a Waiver and Amendment No. 5 to Credit Agreement and Amendment No. 3 to Guarantee and Collateral Agreement (the "March 2015 Second Lien Amendment") to the Second Lien Credit Agreement. The March 2015 Second Lien Amendment, among other things, (i) allows us 60 days from the date of the 2015 Second Lien Amendment to provide a mortgage to the Second Lien Lenders covering the North Fork Pipeline and 30 days from that date to have Savant deliver a mortgage in favor of the Second Lien Lenders covering its oil and gas properties, (ii) adds a requirement that we engage a field auditor and complete a review of our accounts payable, (iii) requires that we deliver to the Second Lien Agent an engineering report on or before May 1, 2015, (iv) amends the provision on "additional interest" to require that we pay an additional 1.0% interest in cash plus 2.0% interest in kind on the loans outstanding under the Second Lien Credit Agreement

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

(subject to future reductions of the additional interest payable in kind if certain operational and capital expenditure conditions are met by May 31, 2015), (v) amends APOD A and certain defined terms, (vi) includes additional restrictions on capital expenditures, (vii) permits us to issue an additional \$50,000 in preferred stock, measured in terms of the stated liquidation preference of that stock (to a total of \$100,000 in stated liquidation preference) and requires that we raise at least \$10,000 of net cash proceeds from the issuance of preferred equity interests on or before April 30, 2015, (viii) amends and updates a list of pledged equity interests attached as Schedule 2 to the associated Guarantee and Collateral Agreement in favor of the Second Lien Lenders, and (ix) provides waivers related to certain events of default resulting from (A) the impairment of our proved reserves, (B) our issuance of preferred equity interests with a stated liquidation preference in excess of \$50,000, (C) the existence of debt in the form of accounts payable that are greater than 90 days past due, (D) our failure to provide an executed mortgage and related legal opinions on the North Fork Pipeline pursuant to a prior amendment, (E) our payment of dividends on our preferred stock while an Event of Default existed, and (F) related cross defaults arising under the First Lien Credit Facility. 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.

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 Nine Months Ended January 31, | |
|--|--|-----------|
| | 2015 | 2014 |
| Sources of cash and cash equivalents: | | |
| Net cash provided by operating activities | \$26,972 | \$15,277 |
| Proceeds from borrowings, net of debt acquisition costs | 50,809 | 18,100 |
| Proceeds from capital lease obligations | 3,250 | — |
| Proceeds from Alaska expenditure and exploration based credits | 36,809 | 18,561 |
| Exercise of equity rights | 1,410 | 4,538 |
| Proceeds from sale of assets | 4,191 | — |
| Issuance of preferred stock, net of issuance costs | 30,576 | 58,811 |
| Release of restricted cash | — | 1,665 |
| Other | — | 3 |
| | 154,017 | 116,955 |
| Uses of cash and cash equivalents: | | |
| Cash dividends | (9,312) | (5,646) |
| Capital expenditures for oil and gas properties | (110,953) | (94,388) |
| Cash paid for Savant acquisition, net of cash acquired | (1,448) | — |
| Deposits for potential acquisitions | — | (3,000) |
| Prepayment of drilling costs | — | (2,302) |
| Purchase of equipment and improvements | (16,318) | (986) |
| Payments on debt | (16,917) | — |
| Principal payments on capital lease obligations | (494) | — |
| Increase in restricted cash | (2,085) | — |
| | (157,527) | (106,322) |

| | | |
|---------------------------------------|----------|------------|
| Increase in cash and cash equivalents | \$(3,510 |) \$10,633 |
|---------------------------------------|----------|------------|

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

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 nine months of fiscal 2015 totaled \$26,972, up \$11,695 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 nine months of our 2015 fiscal year, borrowings totaled \$54,000 under our First Lien RBL, which were offset by a payment of \$10,000 on our First Lien RBL. Additionally, we incurred \$3,343 in deferred financing costs.

During the first nine months of our 2015 fiscal year, increase in restricted cash was \$2,085 as compared to a release of restricted cash of \$1,665 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 nine months of our 2015 fiscal year, we paid \$9,312 in dividends on our Series C and D Preferred Stock, compared to \$5,646 in dividends on our Series C and D Preferred Stock during the first nine months of fiscal 2014.

During the first nine months of our 2015 fiscal year, we received proceeds of \$3,250 under the Rig 36 capital lease. Additionally, we have made payments of \$6,917 in total on the prepayment and extension fee owed to Apollo during the first nine months of fiscal 2015.

During the first nine months of our 2015 fiscal year, we sold 180,032 shares of Series C Preferred stock, yielding net proceeds of \$1,799, and 2,046,574 shares of Series D Preferred Stock, yielding net proceeds of \$28,776. During the same period in fiscal 2014, we sold 1,615,067 shares of Series C Preferred Stock, yielding net proceeds of \$34,065, and 1,069,031 shares of Series D Preferred Stock, yielding net proceeds of \$24,746.

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 nine months ending January 31, 2015, cash paid for capital expenditures was \$127,271, excluding acquisitions.

During the nine months ended January 31, 2015, we collected \$36,809 related to our Alaska production tax credits applied for in prior periods.

Liquidity

Cash and Cash Equivalents

As of January 31, 2015, we had \$2,239 in cash and cash equivalents.

Debt and Available Credit Facilities

As of January 31, 2015, outstanding debt consisted of \$44,000 and \$172,361 under our First Lien RBL and Second Lien Credit Facility, respectively, classified as short-term and long-term debt on the accompanying condensed consolidated balance sheets. As of January 31, 2015, we had no additional borrowing capacity under our Second Lien Credit Facility.

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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 proved properties and other long lived assets;
- asset disposals;
- accretion of asset retirement obligation;
- exploration expense;
- 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 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.

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

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 | | For the Nine Months Ended | |
|--|----------------------------|------------|---------------------------|-------------|
| | January 31, | | January 31, | |
| | 2015 | 2014 | 2015 | 2014 |
| Loss before income taxes | \$(155,277 |) \$(5,273 |) \$(460,134 |) \$(26,658 |
| Adjusted by: | | | | |
| Interest expense, net | 2,478 | 407 | 8,896 | 4,051 |
| Depreciation, depletion and amortization | 19,541 | 7,642 | 56,601 | 22,352 |
| Impairment of proved properties and other long lived assets | 117,037 | — | 230,771 | — |
| Asset disposals | — | — | 47 | — |
| Accretion of asset retirement obligation | 370 | 305 | 1,067 | 903 |
| Exploration expense | 77,740 | 352 | 244,848 | 786 |
| Stock-based compensation | 744 | 1,546 | 10,857 | 5,120 |
| Non-cash employee bonuses | — | — | 1,586 | — |
| Non-recurring litigation settlements and related matters | 2,703 | 1,998 | 7,441 | 1,998 |
| Non-recurring severance payments | — | — | 1,489 | — |
| Non-recurring North Fork properties gas transportation costs | — | — | 1,813 | — |
| Derivative contracts: | | | | |
| (Gain) loss on derivatives, net | (39,330 |) (1,677 |) (55,516 |) 5,589 |
| Cash settlements (paid) received | 7,171 | (983 |) 6,769 | (2,765 |
| Adjusted EBITDA | \$33,177 | \$4,317 | \$56,535 | \$11,376 |

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 nine months ended January 31, 2015, approximately 93% 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 January 31, 2015, we had open oil derivative instruments in a net asset position with a fair value of \$41,540. A 10% increase in oil prices would result in a net asset position with an approximate fair value of \$34,190, while a 10% decrease in prices would result in a net asset position with an approximate fair value of \$48,891.

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 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.

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

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.

| Fiscal | For the Quarter Ended (in barrels) | | July 31, | | October 31, | | January 31, | | April 30, | | Total | |
|--------|------------------------------------|------------|----------|------------|-------------|------------|-------------|------------|-----------|------------|-----------|------------|
| | Volume | Avg. Price | Volume | Avg. Price | Volume | Avg. Price | Volume | Avg. Price | Volume | Avg. Price | Volume | Avg. Price |
| 2015 | — | — | — | — | — | — | 191,400 | 97.09 | 191,400 | 97.09 | 191,400 | 97.09 |
| 2016 | 198,200 | 96.74 | 197,200 | 96.36 | 198,200 | 95.16 | 194,000 | 93.16 | 787,600 | 95.36 | 787,600 | 95.36 |
| 2017 | 148,600 | 93.30 | 50,000 | 95.47 | 34,000 | 94.68 | — | — | 232,600 | 93.97 | 1,211,600 | \$95.37 |

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 10.75% effective on December 10, 2015, 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 nine months ended January 31, 2015, 79% of our total consolidated revenues and 14% 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.

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(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. 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. A bench trial was held January 20, 2015 through January 22, 2015. We received the verdict, dated March 9, 2015, ruling in favor of the Plaintiff and awarding it \$5,463, plus interest. We believe we have grounds to move for a new trial as well as grounds to appeal this decision and are evaluating both options. We expect to file a motion requesting a new trial or notice of appeal in the next few weeks. 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.

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. Pursuant to a motion from PlainsCapital Bank, the case was transferred to Texas. We filed a motion to dismiss the case against the Company on October 9, 2014, which was granted on January 22, 2015. The court did, however, give Vulcan 30 days to replead their concert of action/civil conspiracy claim. An amended complaint as to this cause of action was filed on February 23, 2015. We are currently drafting a responsive pleading. In addition, we note that 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 and natural gas have caused a volatility in prices for oil that could adversely affect our operating results, the price of our common and preferred stock, the borrowing base of our First Lien RBL and our liquidity.

Our revenues and operating results depend highly upon the prices we receive for the crude oil and natural gas we produce. Markets for crude oil and natural gas have been extremely volatile over the course of our fiscal 2015. The market prices for the crude oil and natural gas we expect to sell in the future will depend on factors beyond our control. The results of our operations, the carrying value of certain of our assets, the market price of our common stock and our preferred stock, and the amount available to access additional sources of new liquidity may be significantly adversely affected by further declines in the prices for crude oil or natural gas of the sort that have been observed in recent months, and by continued volatility in those prices.

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

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

between any two redetermination dates after February 1, 2015. The decline in the price of oil has already caused our RBL Lenders to reduce our borrowing base to \$45,000 and to place other restrictions on us designed to limit our ability to draw funds. Similar declines could further 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.

Given our high reliance on a relatively small number of active wells for our non-tax related revenues and production, including any future changes in revenues and production, our business is highly sensitive to issues that may adversely impact the production from our wells.

Miller is highly reliant on a relatively small portfolio of producing wells for its ordinary course revenues and production. Forces which would adversely affect either the ongoing production from our existing producing wells or the projected production from future planned wells could have a significant impact on our revenues and our operating results as a whole. Many of these factors are outside of our control and many of them could arise as a result of actions taken by Company personnel (including reworking of existing wells, attempted maintenance of those wells or related equipment) that fail to have the results anticipated. The oversight of these existing wells, the selection of new drilling candidates and the proper estimation and control of the costs of these activities could result in significant changes in our revenues, production and overall operational results.

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.

The State of Alaska has announced that it is considering reductions in its existing tax credit programs that could limit or eliminate the availability of credits we have relied on in prior periods. If the State of Alaska were to make such changes, it 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 1.5 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 August of 2015.

The oil and gas segment may record impairment losses on its oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives on certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be sufficient enough to cause impairment losses on certain properties that would result in a further non-cash expense to earnings. If natural gas or crude oil prices decline or we drill uneconomic wells, it is reasonably possible we will have a significant impairment.

Our operations of Savant post-acquisition may be hampered by a lack of liquidity and will be subject to the risks and uncertainties inherent in integrating a new business into our operations.

As market pressures have made it harder for us to access our normal sources of liquidity, it may be difficult to find adequate liquidity to devote to drilling plans at the Badami Unit until conditions improve, which they may not do. In addition, we may find that we are unable to successfully integrate Savant's business into our own or to exploit

opportunities arising from its assets and location. We currently have no operations on the North Slope of Alaska other than Savant and this may heighten the difficulty in effectively overseeing, integrating and operating that business. Our operations on the North Slope, and our results of operations, may be adversely affected by the Badami Unit's remote location, limited local infrastructure and extremely cold climate.

Certain unique operational challenges exist for our operations at the Badami Unit as a result of their remote location, limited local infrastructure and the extreme cold present on the Alaska North Slope. This could result in increased transportation

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

and commodity costs, as well as increased operational costs as we are required to keep a minimum amount of production online in order to prevent freezing and the accompanying damage to our infrastructure. Should the price of oil drop below a certain point, production from the field could be uneconomic but we could be required to continue to produce it in order to satisfy pipeline obligations and to protect our infrastructure.

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

None.

ITEM 5. OTHER INFORMATION.

As described more fully in Part II, Item 1 - Legal Proceedings, above, 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. Following a bench trial, we received a verdict in this case, dated March 9, 2015, ruling in favor of the Plaintiff and awarding it \$5,463, plus interest. We believe we have grounds to move for a new trial as well as grounds to appeal this decision and are evaluating both options. We expect to file a motion requesting a new trial or a notice of appeal in the next few weeks.

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 | – |

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|----------|---|--|
| | – | 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 | – | 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). |
| 10.2 | – | 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). |
| †10.3 | – | Employment Agreement with Jeffrey R. McInturff, dated as of December 11, 2014 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 12, 2014). |
| †10.4 | – | Employment Agreement with Kurt C. Yost, dated as of December 11, 2014 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 12, 2014). |
| 10.5 | – | Waiver and Fourth Amendment to Credit Agreement and Second Amendment to Guarantee and Collateral Agreement among the Company, as borrower, KeyBank National Association, as administrative agent, and the lenders party thereto, dated as of March 11, 2015 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K as filed on March 12, 2015). |
| 10.6 | – | Waiver and Amendment No. 5 to Credit Agreement and Amendment No. 3 to Guarantee and Collateral Agreement among the Company, as borrower, Apollo Investment Corporation, as administrative agent, and the lenders party thereto, dated as of March 11, 2015 (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K as filed on March 12, 2015). |
| *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 |

* Filed herewith.

† Indicates management contract or compensatory plan or arrangement.

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SIGNATURES

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

Dated: March 12, 2015

MILLER ENERGY RESOURCES, INC.

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

Dated: March 12, 2015

MILLER ENERGY RESOURCES, INC.

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