MILLER ENERGY RESOURCES, INC.
Form 10-Q
March 12, 2014

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

FORM 10-Q

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

For the quarterly period ended January 31, 2014
OR

o TRANSITION REPORT UNDER 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.
(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 (Address of principal executive offices)	37932 (Zip Code)

Registrant's telephone number, including area code: (865) 223-6575

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. The number of shares of common stock issued and outstanding as of March 5, 2014 was 45,242,197.

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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 per share data)

	January 31, 2014	April 30, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$13,184	$2,551
Restricted cash	4,066	7,531
Accounts receivable	1,137	3,204
Alaska production tax credits receivable	19,763	12,713
Inventory	4,944	3,382
Prepaid expenses and other	8,371	1,183
Total current assets	51,465	30,564
OIL AND GAS PROPERTIES, NET	568,808	491,314
EQUIPMENT, NET	34,860	37,571
OTHER ASSETS:		
Land	542	542
Restricted cash, non-current	12,007	10,207
Deferred financing costs, net	1,607	2,085
Other assets	1,809	541
Total assets	$671,098	$572,824
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$40,538	$13,129
Accrued expenses	18,527	6,338
Short-term portion of derivative instruments	1,758	842
Current portion of long-term debt	—	6,000
Total current liabilities	60,823	26,309
OTHER LIABILITIES:		
Deferred income taxes	145,890	157,530
Asset retirement obligation	20,967	19,890
Long-term portion of derivative instruments	3,152	—
Long-term debt, less current portion	74,268	48,978
Total liabilities	305,100	252,707
COMMITMENTS AND CONTINGENCIES (Note 14)		
MEZZANINE EQUITY:		
Series C Cumulative Preferred Stock, redemption amount of $78,124, 3,250,000 shares authorized, 3,069,968 and 1,454,901 shares issued and outstanding as of January 31, 2014 and April 30, 2013, respectively	67,097	31,236
STOCKHOLDERS' EQUITY:		
	29,885	—

Series D Cumulative Redeemable Preferred Stock, redemption amount of $32,342, 4,000,000 shares authorized, 1,069,031 and 0 shares issued and outstanding as of January 31, 2014 and April 30, 2013, respectively		
Series D Cumulative Redeemable Preferred Stock, held in escrow (Note 10)	(5,000)	—
Common stock, $0.0001 par, 500,000,000 shares authorized, 45,231,447 and 43,444,694 shares issued and outstanding as of January 31, 2014 and April 30, 2013, respectively	4	4
Additional paid-in capital	97,845	88,184
Retained earnings	176,167	200,693
Total stockholders' equity	298,901	288,881
Total liabilities and stockholders' equity	$671,098	$572,824

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 and per share data)

	Three Months Ended January 31,		Nine Months Ended January 31,	
	2014	2013	2014	2013
REVENUES:				
Oil sales	$16,348	$6,720	$47,012	$22,310
Natural gas sales	118	133	671	328
Other	162	1,146	749	4,433
Total revenues	16,628	7,999	48,432	27,071
OPERATING EXPENSES:				
Oil and gas operating	5,821	4,118	18,249	12,963
Cost of other revenue	256	1,051	844	4,084
General and administrative	7,587	5,518	21,092	17,056
Exploration expense	352	187	786	244
Depreciation, depletion and amortization	7,642	3,341	22,352	9,528
Accretion of asset retirement obligation	305	284	903	853
Other operating expense (income), net	1,250	—	1,250	(65)
Total operating expenses	23,213	14,499	65,476	44,663
OPERATING LOSS	(6,585)	(6,500)	(17,044)	(17,592)
OTHER INCOME (EXPENSE):				
Interest expense, net	(407)	(1,117)	(4,051)	(2,785)
Gain (loss) on derivatives, net	1,677	(1,681)	(5,589)	5,215
Other income (expense), net	42	25	26	(350)
Total other income (expense)	1,312	(2,773)	(9,614)	2,080
LOSS BEFORE INCOME TAXES	(5,273)	(9,273)	(26,658)	(15,512)
Income tax benefit	2,171	3,931	11,640	6,551
NET LOSS	(3,102)	(5,342)	(15,018)	(8,961)
Accretion of Series A, C and D preferred stock	(817)	(145)	(1,935)	(2,605)
Series C and D preferred stock cumulative dividends	(2,905)	(677)	(7,573)	(809)
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(6,824)	$(6,164)	$(24,526)	$(12,375)
LOSS PER COMMON SHARE:				
Basic	$(0.15)	$(0.14)	$(0.56)	$(0.29)
Diluted	$(0.15)	$(0.14)	$(0.56)	$(0.29)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:				
Basic	44,886,838	43,367,781	44,141,222	42,445,223
Diluted	44,886,838	43,367,781	44,141,222	42,445,223

See accompanying notes to the condensed consolidated financial statements.

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

	Series D Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings	Total
	Shares	Amount	Shares	Amount			
Balance at April 30, 2012	—	$—	41,086,751	$4	$64,813	$226,188	$291,005
Net loss	—	—	—	—	—	(8,961)	(8,961)
Series C preferred dividends	—	—	—	—	—	(809)	(809)
Accretion of Series A and Series C Preferred Stock	—	—	—	—	—	(2,605)	(2,605)
Issuance of equity for services	—	—	351,477	—	2,047	—	2,047
Other equity issuances	—	—	192,800	—	1,341	—	1,341
Issuance of equity for compensation	—	—	454,665	—	8,710	—	8,710
Exercise of equity rights	—	—	1,286,001	—	3,832	—	3,832
Preferred stock redemption	—	—	—	—	2,510	—	2,510
Modification of warrants	—	—	—	—	1,840	—	1,840
Balance at January 31, 2013	—	—	43,371,694	4	85,093	213,813	298,910
Net loss	—	—	—	—	—	(11,459)	(11,459)
Series C preferred dividends	—	—	—	—	—	(1,400)	(1,400)
Accretion of Series C Preferred Stock	—	—	—	—	—	(261)	(261)
Issuance of equity for services	—	—	—	—	107	—	107
Issuance of equity for compensation	—	—	73,000	—	2,984	—	2,984
Balance at April 30, 2013	—	—	43,444,694	4	88,184	200,693	288,881
Net loss	—	—	—	—	—	(15,018)	(15,018)
Series C preferred dividends	—	—	—	—	—	(6,286)	(6,286)
Accretion of Series C Preferred Stock	—	—	—	—	—	(1,796)	(1,796)
Issuance of Series D Preferred Stock	1,282,617	29,746	—	—	—	—	29,746
Series D Preferred Stock held in escrow	(213,586)	(5,000)	—	—	—	—	(5,000)
Series D preferred dividends	—	—	—	—	—	(1,287)	(1,287)
Accretion of Series D Preferred Stock	—	139	—	—	—	(139)	—
	—	—	—	—	752	—	752

Issuance of equity for services							
Other equity issuances	—	—	—	—	3	—	3
Issuance of equity for compensation	—	—	205,099	—	4,368	—	4,368
Exercise of equity rights	—	—	1,581,654	—	4,538	—	4,538
Balance at January 31, 2014	1,069,031	$24,885	45,231,447	$4	$97,845	$176,167	$298,901

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, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(15,018)	$(8,961)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	22,352	9,528
Amortization of deferred financing fees and debt discount	1,113	549
Expense from issuance of equity	5,120	7,630
Dry hole costs, leasehold impairments and non-cash exploration expenses	157	—
Deferred income taxes	(11,640)	(6,551)
Derivative contracts:		
(Gain) loss on derivatives, net	5,589	(5,215)
Cash settlements	(2,765)	2,276
Accretion of asset retirement obligation	903	853
Other	1,949	—
Changes in operating assets and liabilities:		
Receivables	5,084	996
Inventory	372	(467)
Prepaid expenses and other assets	(1,788)	(1,445)
Accounts payable, accrued expenses and other	3,849	6,944
NET CASH PROVIDED BY OPERATING ACTIVITIES	15,277	6,137
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures for oil and gas properties	(94,388)	(23,213)
Proceeds from Alaska production tax credits for capital expenditures	18,561	—
North Fork purchase deposit	(3,000)	—
Prepayment of drilling costs	(2,302)	—
Purchase of equipment and improvements	(986)	(9,606)
Proceeds from sale of equipment	—	2,000
NET CASH USED IN INVESTING ACTIVITIES	(82,115)	(30,819)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Cash dividends	(5,646)	(285)
Payments on debt	—	(24,130)
Proceeds from borrowings	20,000	40,000
Debt acquisition costs	(1,900)	(3,854)
Redemption of preferred stock	—	(11,240)
Issuance of preferred stock	62,704	20,448
Equity issuance costs	(3,893)	(1,576)
Exercise of equity rights	4,538	3,832
Restricted cash	1,665	(992)
Other	3	—
NET CASH PROVIDED BY FINANCING ACTIVITIES	77,471	22,203
NET CHANGE IN CASH AND CASH EQUIVALENTS	10,633	(2,479)

CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,551	3,971
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$13,184	$1,492
SUPPLEMENTARY CASH FLOW DATA:		
Cash paid for interest	$5,805	$8,895
SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Capital expenditures in accounts payable and accrued expenses	$32,572	$6,702
Reduction of oil and gas properties and equipment from applications for Alaska production tax credits	$28,906	$—
Issuance of Series D Preferred Stock held in escrow	$5,000	$—
Accretion of preferred stock	$1,935	$2,605

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, Inc.," the "Company," "we," "us," "ours," "MER," "Miller," and similar terms refer to our Tennessee corporation Miller Energy Resources, Inc., formerly known as Miller Petroleum, Inc., and our subsidiaries, Miller Rig & Equipment, LLC, Miller Drilling, TN LLC, Miller Energy Services, LLC, East Tennessee Consultants, Inc., East Tennessee Consultants II, LLC, Miller Energy GP, LLC, and Cook Inlet Energy, LLC ("CIE"), collectively.

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

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, 2013, which was filed with the SEC on July 15, 2013 and was amended on August 28, 2013. Certain amounts in the condensed consolidated financial statements and notes thereto have been reclassified to conform to current period presentation.

Immaterial Reclassifications to Prior Period Consolidated Balance Sheets

We reclassified a $5,305 contra asset related to Alaska production tax credits from oil and gas properties to equipment. The credits that resulted in the recognition of the contra asset related to our drilling rigs, the costs of which are classified in equipment. We have determined the reclassification to be immaterial to the prior period consolidated balance sheet taken as a whole. This error did not have an impact on the prior period consolidated statements of operations, equity or cash flows.

	As Presented April 30, 2013	Reclassifications	As Adjusted April 30, 2013
Oil and gas properties, net	$486,009	$5,305	$491,314
Equipment, net	$42,876	$(5,305)	$37,571

In addition, we reclassified certain costs related to the issuance of debt under our Prior Credit Facility that were paid to our lender. The costs were initially recorded and reflected as deferred financing costs on our condensed consolidated balance sheet and have been reclassified as a debt discount. We have determined the reclassification to be immaterial to the prior period consolidated balance sheet taken as a whole. This error did not have an impact on the prior period consolidated statements of operations, equity or cash flows.

	As Presented		As Adjusted

	April 30, 2013	Reclassifications	April 30, 2013
Deferred financing costs, net	$4,666	$(2,581)	$2,085
Long-term debt, less current portion	$51,559	$(2,581)	$48,978

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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)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are consistent with those disclosed in our Annual Report on Form 10-K for the year ended April 30, 2013, as amended.

Principles of Consolidation

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

Use of Estimates

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

Restricted Cash

As of January 31, 2014 and April 30, 2013, current restricted cash includes $3,447 and $7,144, respectively, of cash temporarily held in an account that is controlled by our lender. Current restricted cash balances also include amounts held in escrow to secure Company related credit cards and certain amounts held for and to be paid out to working interest owners. Non-current restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, the possible dismantling of our off-shore platform, performance bonds and general liability bonds.

Oil and Gas Properties

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

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

When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future net cash flows, calculated using the Company's estimate of future oil and natural gas prices, operating expenses and production, to the net book value of the proved properties on a field by field basis. If the sum of the expected undiscounted future net cash flows is less than the net book value of the proved properties, an impairment loss is recognized for the excess, if any, of the net book value over its estimated fair value. No impairment of proved properties was recognized during the nine months ended January 31, 2014 or January 31, 2013.

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. During the nine months ended January 31, 2014 our condensed consolidated statement of operations includes $157 related to impairment of certain unproved properties and $625 in seismic and delay rentals incurred in the Cook Inlet region. We had $4 in exploration and abandonment expenses in the Appalachian region during the nine months ended January 31, 2014.

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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)

Equipment

Equipment includes drilling rigs, automobiles, trucks, an airplane, office furniture, computer equipment, and buildings. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from five to forty years.

Equipment is reviewed for impairment when facts and circumstances indicate that book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted estimated future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Investments

On June 24, 2011, we acquired a 48% minority interest in Pellissippi Pointe I, LLC and Pellissippi Pointe II, LLC (the "Pellissippi Pointe" entities or "investee") for total cash consideration of $400. In connection with the transaction, we executed a five-year lease agreement with the investee and relocated our corporate offices to the new facility on November 7, 2011. Since we do not exercise control over the financial and operating decisions made by the investee, we have accounted for these investments using the equity method. These investments are reflected in other assets in the accompanying condensed consolidated balance sheets.

Guarantees

On July 12, 2012, we signed a direct guarantee for 55% of the $5,074 outstanding loan obligations with FSG Bank for the Pellissippi Pointe equity investment. The Company's guarantee is included within the scope of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 460, "Guarantees" and was recorded at the estimated fair value of $250; such amount is included in accrued expenses on our condensed consolidated balance sheet as of January 31, 2014 and is being amortized over the five-year life of the guarantee. The fair value was calculated using the income approach and the estimated default rate was determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of Pellissippi Pointe and the term of the underlying loan obligations. The default rates are published by Moody's Investors Service. To the extent we are required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings. At January 31, 2014, our maximum potential undiscounted payment under this arrangement is $2,791 plus additional lender's costs.

Loss Per Share

We determine basic income (loss) per share and diluted income (loss) per share in accordance with the provisions of ASC 260, “Earnings Per Share.” Basic income (loss) per share excludes dilution and is computed by dividing earnings available to common stockholders by the weighted-average number of common shares outstanding for the period. The calculation of diluted earnings (loss) per share is similar to that of basic earnings per share, except that the denominator is increased, if net income is positive, to include the number of additional common shares that would have been outstanding if all potentially dilutive common shares, such as those issuable upon the exercise of stock options and warrants, had been exercised. We compute the numerator for basic income (loss) by subtracting accretion of preferred stock and cumulative preferred stock dividends from net income (loss) to arrive at net income (loss) attributable to common stockholders. Preferred stock dividends include dividends declared on preferred stock (regardless of whether the dividends have been paid) and dividends accumulated for the period on cumulative preferred stock (regardless of whether the dividends have been declared). As of January 31, 2014 our cumulative dividends were $7,573.

New Accounting Pronouncements

In December 2011, the FASB issued Accounting Standards Update ("ASU") 2011-11, "Disclosures about Offsetting Assets and Liabilities," which increases disclosures about offsetting assets and liabilities. The new disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared under GAAP and International Financial Reporting Standards ("IFRS") related to the offsetting of financial instruments. The existing GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. The guidance in ASU 2011-11 was effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. We have adopted ASU 2011-11; however, it did not have a material impact to our condensed consolidated financial statements There are no other recently issued accounting pronouncements that are expected to have a material impact on our financial condition, results of operations or cash flows.

3. MAJOR CUSTOMERS AND CONCENTRATIONS OF CREDIT RISK

For the three and nine months ended January 31, 2014, Tesoro Corporation accounted for 95% and 93% of our consolidated total revenues, respectively. Tesoro Corporation also accounted for 14% and 55%, of our accounts receivable as of January 31, 2014 and April 30, 2013, respectively.

Credit is extended to customers based on an evaluation of their credit worthiness and collateral is generally not required. We experienced no credit losses of significance during the nine months ended January 31, 2014 or 2013.

We maintain our cash and cash equivalents (including restricted cash), which at times may exceed federally insured amounts, in highly rated financial institutions. As of January 31, 2014, we held $15,677 in excess of the $250 limit insured by the Federal Deposit Insurance Corporation.

4. RELATED PARTY TRANSACTIONS

We use a number of contract labor companies to provide on demand labor at our Alaska operations. H&H Industrial, Inc. ("H&H Industrial") is an entity contracted by CIE, a wholly-owned subsidiary of the Company, to provide services related to the exploration and production of oil and natural gas. H&H Industrial is owned by the sister and father of David Hall, who is a member of our Board of Directors and Chief Operating Officer ("COO") of Miller, as well as the Chief Executive Officer ("CEO") of CIE. For the three and nine months ended January 31, 2014, we paid H&H Industrial a total of $450 and $1,349, respectively. We have used Rediske Air, Inc. ("Rediske Air") to provide transportation to our facilities. Rediske Air was owned by David Hall's brother-in-law, who passed away on July 7, 2013. Rediske Air is no longer owned by a related party. For the three and nine months ended January 31, 2014, we paid Rediske Air a total of $281 and $865, respectively. The Audit Committee of our Board of Directors determined that the amounts paid by us for the services performed were fair and in the best interest of the Company.

The Company is required to remit payroll taxes related to certain stock-based compensation transactions. As of January 31, 2014, we had a payable of $36 and no receivable. At April 30, 2013, we had a payable of $620 and a corresponding receivable from the respective employees of $593, which was collected subsequent to April 30, 2013.

In 2009, we formed both Miller Energy GP and Miller Energy Income 2009-A, LP ("MEI") to raise capital necessary to support strategic business initiatives. From November 2009 to May 2010 we entered into three secured promissory notes with MEI to borrow $3,071 with maturity dates ranging from November 2013 to May 2014. On June 29, 2012, the maturity dates on the promissory notes were amended to reflect the later of (i) 91 days after the date on which the Apollo Credit Facility is extinguished, or (ii) July 31, 2017. Our wholly owned subsidiary, Miller Energy GP, owns 1% of MEI; however, due to the shared management of our company and MEI, we consolidate this entity. We have not presented non-controlling interest on our condensed consolidated balance sheets or our condensed consolidated statements of operations since these amounts are immaterial.

On September 18, 2013, the Company entered into a one-year consulting agreement with William R. Weakley under which he agreed to assist us with investor relations and outreach, including advising the company on its communications with high net-worth individuals, helping to further the Company’s related business goals, assisting with our strategic planning, providing management and business advice, and other consulting services we may reasonably request. Mr. Weakley is a related party to the Company as a result of aggregating his personal holdings in our stock with those of his brother, son-in-law and other of his relatives which, taken together, exceed 5% of the outstanding common stock of the Company. As compensation for these services, we granted Mr. Weakley a warrant to purchase 300,000 shares of our common stock at an exercise price of $6.63 per share. So long as the warrant has not otherwise terminated prior to that date, this warrant will vest in full and be exercisable on September 18, 2014. The warrant will terminate if the related consulting agreement is terminated prior to the end of its one-year term. The warrant will otherwise terminate on the earlier of the one year anniversary of the death or disability of Mr. Weakley or September 18, 2016. The Audit Committee of our Board of Directors determined that the consideration given by us for the services to be performed was fair and in the best interest of the Company. We further note that in an unrelated transaction, Mr. Weakley's son-in-law extended a personal loan to our CEO, Scott M. Boruff. The Company is not a party to or otherwise involved in this loan, though this transaction was disclosed to the Audit Committee of our Board of Directors in connection with its evaluation of the consulting agreement with Mr. Weakley. For the three and nine months ended January 31, 2014, we paid Mr. Weakley a total of $2 and $2, respectively.

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(Unaudited)
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5. OIL AND GAS PROPERTIES AND EQUIPMENT

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

	January 31, 2014	April 30, 2013
Property costs		
Proved property	$389,810	$332,241
Unproved property	235,134	196,500
Total property costs	624,944	528,741
Less: Accumulated depletion	(56,136)	(37,427)
Oil and gas properties, net	$568,808	$491,314

Equipment is summarized as follows:

	January 31, 2014	April 30, 2013
Machinery and equipment	$7,748	$7,413
Vehicles	1,877	1,851
Aircraft	476	476
Buildings	2,725	2,725
Office equipment	812	759
Leasehold improvements	485	482
Drilling rigs	30,117	30,117
	44,240	43,823
Less: Accumulated depreciation	(9,380)	(6,252)
Equipment, net	$34,860	$37,571

Depreciation, depletion and amortization consisted of the following:

	For the Nine Months Ended January 31,	
	2014	2013
Depletion of oil and gas related assets	$19,158	$7,240
Depreciation and amortization of equipment	3,194	2,288
Total	$22,352	$9,528

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6. DERIVATIVE INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Derivative Instruments
Commodity Derivatives
We are exposed to fluctuations in crude oil prices on the majority of our production. As a result, our management believes it is prudent to manage the variability in cash flows by occasionally entering into hedges on a portion of our crude oil production. We primarily utilize over-the-counter variable-to-fixed price commodity swap contracts to manage fluctuations in cash flows resulting from changes in commodity prices. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. In accordance with ASC 815 "Derivatives and Hedging," the changes in fair value are recognized in the condensed consolidated statement of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.
As of January 31, 2014, we had the following open crude oil derivative positions. All are priced based on the Brent crude oil futures as traded on the Intercontinental Exchange.

	Fixed - Price Swaps	
Production Period ending April 30,	Bbls	Weighted Average Fixed Price
2014	191,400	$102.92
2015	785,000	100.58
2016	787,600	95.75
2017	232,600	94.27

Derivative Activities Reflected on Condensed Consolidated Balance Sheets
The Company reports the fair value of derivatives on the condensed consolidated balance sheets in derivative instrument assets and derivative instrument liabilities as either current or noncurrent. The Company determines the current and noncurrent classification based on the timing of the expected future cash flows of individual trades. The Company reports these amounts on a net basis by counterparty where right of offset or master netting agreements exists. As of January 31, 2014 and April 30, 2013, the fair market value of our derivative liabilities was as follows:

	Asset Derivatives				Liability Derivatives			
	January 31, 2014		April 30, 2013		January 31, 2014		April 30, 2013	
Derivatives not designated as hedging instruments under ASC 815	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity derivatives	Prepaid expenses and other	$564	Prepaid expenses and other	$—	Current portion of derivative instruments	$(1,758)	Current portion of derivative instruments	$(842)
Commodity derivatives	Other assets	680	Other assets	—	Long-term portion of	(3,152)	Long-term portion of	—

			derivative instruments	derivative instruments
Total derivatives not designated as hedging instruments under ASC 815	$1,244	$—	$(4,910)	$(842)

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

Offsetting of Derivative Assets and Liabilities

The following table presents our gross and net derivative assets and liabilities:

	Gross Amount	Netting Adjustments [a]	Net Amount Presented on Balance Sheet
January 31, 2014			
Derivative assets with right of offset or master netting agreements	$1,244	$—	$1,244
Derivative liabilities with right of offset or master netting agreements	$(4,910)	$—	$(4,910)
April 30, 2013			
Derivative assets with right of offset or master netting agreements	$—	$—	$—
Derivative liabilities with right of offset or master netting agreements	$(842)	$—	$(842)

(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 January 31,		For the Nine Months Ended January 31,	
	2014	2013	2014	2013
Gain (loss) on derivatives, net	$1,677	$(1,681)	$(5,589)	$5,215

Fair Value Measurements

Fair Value Hierarchy

ASC 820, "Fair Value Measurements and Disclosures," provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and excess earnings method. A cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

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

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis as of January 31, 2014 and April 30, 2013. The carrying amounts reported in the condensed consolidated balance sheets for cash and cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	Fair Value Measurements		
At January 31, 2014	Level 1	Level 2	Level 3
Commodity derivative asset	$—	$1,244	$—
Commodity derivative liability	$—	$(4,910)	$—
Total	$—	$(3,666)	$—
At April 30, 2013			
Commodity derivative asset	$—	$—	$—
Commodity derivative liability	$—	$(842)	$—
Total	$—	$(842)	$—

Our commodity derivatives consist of over-the-counter variable-to-fixed price commodity swaps. The fair values of our commodity derivatives are not actively quoted in the open market, thus we use an income approach to estimate fair value. Significant level 2 assumptions used to measure the fair value of the commodity derivatives include current market and contractual crude oil prices, appropriate risk adjusted discount rates, and other relevant data. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers between Level 1, Level 2 or Level 3 during the nine months ended January 31, 2014 or 2013.

7. DEBT

As of January 31, 2014 and April 30, 2013, we had the following debt obligations reflected at their respective carrying values on our condensed consolidated balance sheets:

	January 31, 2014	April 30, 2013
Apollo senior secured Credit Facility	$75,307	$55,307
Debt discount related to Apollo senior secured Credit Facility	(3,346)	(2,581)
Series B Preferred Stock	2,307	2,252
Total debt obligations	$74,268	$54,978

Apollo Senior Secured Credit Facility

On June 29, 2012 (the "Closing Date"), we entered into a Loan Agreement (the "Prior Loan Agreement") with Apollo Investment Corporation ("Apollo"), as administrative agent and sole initial lender. The Prior Loan Agreement provided for a $100,000 credit facility (the "Prior Credit Facility") with an initial borrowing base of $55,000 (the "Original Availability"). Of that initial $55,000, $40,000 was made available to and was drawn by us on the Closing Date. On February 7, 2013 and April 25, 2013, we borrowed an additional $5,000 and $10,000, respectively, under the Prior Credit Facility, exhausting the Original Availability. On August 5, 2013, the amount available to us under the Prior Credit Facility was increased by an additional $20,000, to a total of $75,000, when a second tranche of loans (the "Additional Availability") was added to the Prior Loan Agreement after negotiations with Apollo. This additional

$20,000 in availability was immediately drawn by us.

As noted below, on February 3, 2014, we refinanced the Prior Credit Facility by entering into an Amended and Restated Credit Agreement (the "New Loan Agreement") among us, as a borrower, Apollo, as administrative agent (in that capacity the "Administrative Agent"), and the lenders from time to time party thereto (the "Lenders"), which amended and replaced the terms of the Prior Credit Facility.

The Prior Credit Facility was scheduled to mature on June 29, 2017 and was secured by substantially all of our assets and those of our consolidated subsidiaries (other than MEI), which subsidiaries also guaranteed the loans. Except as described below in connection with the Additional Availability, amounts outstanding under the Prior Credit Facility bore interest at a rate of 18% per annum, with interest payable on the last day of each of our fiscal quarters. We would have been required to pay the outstanding balance of the loan in full on the maturity date; however, beginning with the fiscal quarter ending July 31, 2013, if requested by Apollo (at the direction of lenders holding a majority of the commitments under the Prior Loan Agreement), we would have been required to repay up to $1,500 in principal quarterly. Such payments of principal would have been made, together with any interest due on such date, on the last day of our fiscal quarter. No such request to repay principal was made by Apollo.

In addition, the outstanding debt includes paid in kind interest of $307 added to the principal amount as a part of the "PIK Election" as defined in the Prior Loan Agreement. In connection with the Prior Loan Agreement, we have granted Apollo a right of first refusal to provide debt financing for the acquisition, development, exploration or operation of any oil and gas related properties, including wells, during the term of the Prior Credit Facility and one year thereafter.

The Prior Loan Agreement contained interest coverage, asset coverage, minimum gross production covenants, as well as other affirmative and negative covenants. As previously reported, these covenants were amended several times to adjust the covenant levels and the date on which compliance with the covenants would be measured, and to include our Tennessee production in the minimum production covenant. As of April 30, 2013, we were not in compliance with such covenants; however, we received a waiver of such violations from Apollo on July 11, 2013. Under the terms of the waiver, we were required to maintain compliance with the financial and production covenants on a quarterly basis commencing with the quarter ending October 31, 2013. As of October 31, 2013, we were in compliance with the asset coverage and minimum gross production covenants, but not the interest coverage ratio covenant. On December 9, 2013, we received an amendment and waiver from Apollo ("Eighth Amendment") which, among other matters, waived our non-compliance with the interest coverage ratio requirement as of October 31, 2013 and amended our next testing date for the interest coverage ratio to October 31, 2014. As we refinanced the Prior Credit Facility, we were not required to calculate compliance with the Prior Loan Agreement's financial covenants at January 31, 2014.

On the Closing Date, we paid Apollo a non-refundable structuring fee of $2,750, payable for the benefit of the lenders, and we have agreed to pay an additional 5% fee to Apollo for the benefit of the lenders on the amount of every additional borrowing over and above the Original Availability. In addition, we paid Apollo a supplemental fee of $500 on the Closing Date and had agreed to pay another $500 fee on each anniversary of the Closing Date so long as the Prior Loan Agreement remained in effect.

Additional compensation was due to Bristol Capital, LLC, a consultant to us, in connection with the closing of the Prior Loan Agreement. This fee was paid by issuing 312,500 shares of the Company's restricted common stock based on the amount of the Original Availability.

We used a portion of the initial $40,000 loan made available under the Prior Credit Facility to repay in full the amounts outstanding under the Guggenheim Senior Secured Credit Facility ("Guggenheim Credit Facility") of approximately $26,200. The remaining $13,800 was used to (i) redeem our outstanding Series A Preferred Stock; (ii) pay certain outstanding payables; and (iii) pay transaction costs associated with the closing of the Prior Credit Facility, such as attorneys' fees. The February and April 2013 borrowings were used to fund our drilling projects and pay outstanding operational and general and administrative expenses otherwise permitted under the Prior Credit Facility.

On August 5, 2013, we entered into Amendment No. 6 to the Prior Credit Facility (the "Sixth Amendment") as modified by an Extension of Date for Prepayment of Tranche B Loan without Prepayment Premium (the "Extension Agreement"). The Amendment added the Additional Availability to the Prior Loan Agreement. This Additional Availability was drawn by us immediately and used for capital projects and working capital and was not initially subject to any pre-payment penalty, and was subject to an initial reduced interest rate of 9%. Under the terms of the Sixth Amendment as modified by the Extension Agreement, in the event that we had not repaid the entire outstanding amount of the loans made to date under the Prior Credit Facility ("Loans") on or before February 28, 2014, then the pre-payment penalty would have applied to the Additional Availability after that date and the interest rate on the Additional Availability would increase to 18%. The Sixth Amendment clarified that when and if any prepayment of the Loans is made from the proceeds of tax credits received by us under Alaska's Clear and Equitable Share program, that pre-payment would be applied pro rata to both the Additional Availability and previously drawn Loans (the "Prior Loans").

In addition to the increase in the amounts available to be borrowed and the adjustment to the interest rate and prepayment penalties on those amounts, among other things, the Sixth Amendment: (i) clarified that the option under the Prior Loan Agreement to pay interest in-kind, rather than in cash, applied to the Prior Loans only and not the Additional Availability, (ii) established separate conditions precedent to borrowings from the Additional Availability, (iii) adjusted restrictions contained in Sections 7.10

and 7.12 of the Prior Loan Agreement, and (iv) established interpretive rules related to the repayment and pre-payment of the Loans.

On September 20, 2013, we entered into Revised and Restated Consent and Amendment No. 7 (the "Seventh Amendment") with Apollo under the Prior Loan Agreement. The Seventh Amendment amended and made certain acknowledgments regarding certain provisions of the Prior Loan Agreement allowing for our issuance of our Series D Preferred Stock and the payment of dividends on the series. Among other things, the Seventh Amendment: (i) permitted the filing of supplementary articles amending our charter, designating the terms of the Series D Preferred Stock; (ii) clarified the treatment of the Series D Preferred Stock under the Prior Loan Agreement; (iii) so long as no default or event of default has occurred, allowed payment of dividends on our Series D Preferred Stock, our Series B Preferred Stock and our Series C Preferred Stock either out of Excluded Equity Proceeds (as defined in the Prior Loan Agreement) or during a Capital Covenant Compliance Period (as defined in the Prior Loan Agreement), provided that we are in compliance with the Capital Covenants (as defined in the Prior Loan Agreement) on a pro forma basis on the date of payment, (iv) restricted our ability to redeem the Series D Preferred Stock prior to the 30th day following Security Termination (as defined in the Prior Loan Agreement); and (v) prohibited us from modifying the terms of the Series D Preferred Stock without Apollo's prior written consent.

The Seventh Amendment also extended the date by which certain liens must be lifted, as a result of the rescheduling of the Voorhees arbitration (see Note 13 - Litigation).

As noted above, on February 3, 2014, we refinanced the Prior Credit Facility by entering into the New Loan Agreement among us, the Administrative Agent, and the Lenders. The New Loan Agreement provides for a $175,000 credit facility, which was fully drawn by us at closing, at an interest rate of LIBOR plus 9.75%, with a 2% LIBOR floor (see Note 15 - Subsequent Events).

The fair value of the outstanding balance of the Prior Credit Facility was $69,042 as of January 31, 2014, as calculated using the discounted cash flows method.

Series B Preferred Stock

On September 24, 2012, we sold 25,750 shares of our Series B Cumulative Redeemable Preferred Stock (the "Series B Preferred Stock") to 10 accredited investors and issued those investors warrants to purchase 128,750 shares of common stock in a private offering exempt from registration under the Securities Act of 1933, as amended. We received gross proceeds of $2,575. We paid issuance costs of $167, which have been capitalized and are being amortized over the term of the instrument. The outstanding Series B Preferred Stock is classified as long-term debt, in accordance with ASC 480, "Distinguishing Liabilities from Equity." As of January 31, 2014, the fair value of Series B Preferred Stock was $2,326, as calculated using the discounted cash flow method.

The designations, rights and preferences of the Series B Preferred Stock, include:

- a stated value of $100 per share and a liquidation preference equal to the stated value;
- the holders are not entitled to any voting rights and the shares of Series B Preferred Stock are not convertible into any other security;
- the holders are entitled to receive annual cumulative dividends at the rate of 12% per annum, payable in arrears semi-annually, which began on March 1, 2013;
- dividends will be paid in cash on each relevant dividend date provided that (i) we are in compliance with certain financial covenants (designated the "Capital Covenants") under the Prior Credit Facility or any amendments thereto, with compliance to be determined as of the most recent reporting date and, on a pro forma basis, on the dividend date, and (ii) no "Default" or "Event of Default" (as defined in the Prior Credit Facility or any amendments thereto) has occurred or is continuing on the dividend date;
-

the shares may not be redeemed until 30 days after "Security Termination" (as defined in the Prior Credit Facility), but otherwise may be redeemed at any time by the Company, with a required redemption on the fifth anniversary of issuance or, if later, on the 30th day after Security Termination.

On March 1, 2013, in accordance with our charter and the designations for the Series B Preferred Stock, we paid a semiannual dividend of approximately $5.16 per share on the Series B Preferred Stock.

On July 18, 2013, our Board approved the payment of a semiannual dividend of approximately $6.05 per share, which was paid on September 3, 2013 as the regularly scheduled payment date of September 1, 2013 was not a business day. The record date was August 15, 2013.

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

On January 28, 2014, our Board approved a semiannual dividend to shareholders of record at the close of business on February 17, 2014. The semiannual payment will be approximately $5.95 per share, which is equivalent to an annualized yield of 12%. The dividend was paid on March 3, 2014 as the regularly scheduled payment date of March 1, 2014 was not a business day. The record date was February 17, 2014.

Debt Issue Costs

As of January 31, 2014 and April 30, 2013, our unamortized deferred financing costs were $1,607 and $2,085, respectively, which relates to the Prior Credit Facility and the Series B Preferred Stock. As of January 31, 2014 and April 30, 2013, our unamortized debt discount, which relates to the Prior Credit Facility, was $3,346 and $2,581, respectively. These costs are being amortized over the term of the respective debt instruments.

8. ASSET RETIREMENT OBLIGATIONS

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

	For the Nine Months Ended January 31,	
	2014	2013
Asset retirement obligation, as of April 30	$19,890	$18,366
Additions	196	—
Settlements and adjustments	(22)	—
Accretion expense	903	853
Asset retirement obligation, as of January 31	$20,967	$19,219

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. At January 31, 2014 and April 30, 2013, there were no significant expenditures for abandonments.

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9. STOCK-BASED COMPENSATION

During fiscal years 2010 and 2011, our Compensation Committee and Board of Directors adopted share-based compensation plans authorizing 3,000,000 and 8,250,000 shares of common stock under each plan, respectively. The share-based compensation plans allow us to offer our employees, officers, directors and others an opportunity to acquire a proprietary interest in the Company and enable us to attract, retain, motivate and reward such persons in order to promote our success. Each plan authorizes the issuance of incentive stock options, nonqualified stock options and restricted stock. All awards issued under the share-based compensation plans must be approved by our Compensation Committee. On June 21, 2013 and July 29, 2013, our Compensation Committee approved additional grants of 350,000 shares of restricted stock and 7,299,996 options to purchase our common stock (the "Q1 Grants"). The grant of these 7,299,996 options to purchase shares of our common stock was included in certain employment agreements between the Company and certain executive officers, Scott M. Boruff, David J. Voyticky, David M. Hall, Deloy Miller and Kurt C. Yost. On March 10, 2014, these officers entered into an amendment to their employment agreements with the Company under which the 7,299,996 options to purchase shares of our common stock will no longer be granted. On October 11, 2013, the Compensation Committee approved an additional grant of 41,000 shares of restricted stock and an option to purchase 30,000 shares of our common stock (the "Q2 Grants"). On November 12, 2013, the Compensation Committee approved an option to purchase 800,000 shares of our common stock (the "Q3 Grants"). The Q1 Grants, Q2 Grants and Q3 Grants are contingent upon shareholder approval of an increase in the number of shares available under the 2011 share-based compensation plan and have not been included in our calculation of available shares. At January 31, 2014 and April 30, 2013, there were 77,078 and 329,328 additional shares available under the compensation plans, 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, 2014 of approximately $1,343 and $4,368, respectively, and $2,549 and $7,077 for the three and nine months ended January 31, 2013, respectively. We also recognized non-employee expense related to warrants issued for the three and nine months ended January 31, 2014 of approximately $203 and $752, respectively, and $103 and $290 for the three and nine months ended January 31, 2013, respectively.

The following table summarizes stock options and warrants activity for the nine months ended January 31, 2014:

	For the Nine Months Ended January 31, 2014	
	Number of Options and Warrants	Weighted Average Exercise Price
Beginning balance at April 30	14,403,847	$4.61
Granted	932,500	5.50
Exercised	(1,581,654)	2.84
Canceled	(58,346)	4.12
Ending balance	13,696,347	4.87
Options exercisable at January 31	10,593,495	$4.70

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

Options and Warrants Outstanding				Options and Warrants Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.01 to $1.82	1,606,400	1.4	$0.72	1,606,400	$0.72
$2.00 to $4.99	1,783,000	5.7	3.55	1,263,485	3.30
$5.25 to $5.53	3,936,947	2.7	5.32	2,636,947	5.32
$5.89 to $5.94	3,295,000	6.6	5.92	2,936,663	5.93
$6.00 to $6.94	3,075,000	2.0	6.12	2,150,000	6.08
	13,696,347	3.7	$4.87	10,593,495	$4.70

The following table summarizes restricted stock activity for the nine months ended January 31, 2014:

	For the Nine Months Ended January 31, 2014
Unvested at April 30	591,030
Granted	—
Vested	(220,849)
Forfeited	(12,750)
Unvested at January 31	357,431

10. STOCKHOLDERS' EQUITY

Common Stock

At January 31, 2014, we had 45,231,447 shares of common stock outstanding. We issued 1,786,753 shares during the nine months ended January 31, 2014, of which 205,099 shares were issued to employees for compensation, and 1,581,654 shares were related to the exercise of equity rights.

At January 31, 2013, we had 43,371,694 shares of common stock outstanding. We issued 2,284,943 shares during the nine months ended January 31, 2013, of which 312,500 shares were issued to Bristol Capital, LLC as payment for fees related to the closing of our credit facility, 454,665 shares were issued to employees and non-employees for compensation, 178,800 shares were issued for the settlement of an obligation, 14,000 shares were issued for oil and gas leases, and 1,286,001 shares were related to the exercise of equity rights.

Series C Preferred Stock

On September 28, 2012, we sold 685,000 shares of the Company's newly designated 10.75% Series C Cumulative Redeemable Preferred Stock (the "Series C Preferred Stock"). These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated September 28, 2012, and the Company's registration statement on Form S-3 (Registration No. 333-183750), which was declared effective by the SEC on September 18, 2012. The shares were offered to the public at $23.00 per share for gross proceeds of $15,755. We incurred issuance costs of $1,335, yielding net proceeds of $14,420.

On October 12, 2012, we entered into an At Market Issuance Sales Agreement ("Series C ATM Agreement") with MLV & Co. LLC ("MLV"). The Series C ATM Agreement contemplates periodic sales by MLV of our Series C Preferred Stock as and when directed by the Company. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated October 12, 2012, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012. On and after October 12, 2012 and through January 31, 2014, we sold 780,067 shares of Series C Preferred Stock under the Series C ATM Agreement and related prospectus supplement at prices ranging from $21.48 per share to $26.71 per share. We received gross proceeds of $17,710 and incurred issuance costs of $620, yielding net proceeds of $17,090.

On February 12, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 625,000 shares of the Series C Preferred Stock in this offering at a price of $22.90 per share. We received gross proceeds of $14,312 and incurred issuance costs of $1,052, yielding net proceeds of $13,260 in connection with the offering. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated February 13, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

On May 7, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 500,000 shares of our Series C Preferred Stock, at a price of $22.25 per share. We received gross proceeds of $11,125 and incurred issuance costs of $805, yielding net proceeds of $10,320. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated May 7, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

On June 27, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 335,000 shares of our Series C Preferred Stock, at a price of $21.50 per share. We received gross proceeds of $7,203 and incurred issuance costs of $547, yielding net proceeds of $6,656. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated June 28, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

The Series C Preferred Stock is classified as temporary equity in accordance with ASC 480 and is being accreted to redemption value through the earliest repayment date of November 1, 2017, which resulted in accretion of $1,796 during the nine months ended January 31, 2014. The fair value of the Series C Preferred Stock was $79,942 as of January 31, 2014, based on the closing price on that date. The designations, rights and preferences of the Series C Preferred Stock include:

- The holders are entitled to receive a 10.75% per annum cumulative quarterly dividend, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited by making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);
- The dividend may increase to a penalty rate of 12.75% if we fail to (A) pay dividends for four or more quarterly dividend periods, whether or not consecutive, or (B) maintain the listing of our Series C Preferred Stock on a national securities exchange (the events listed in clauses (A) and (B) being "Penalty Events");
- There is no mandatory redemption or stated maturity with respect to the Series C Preferred Stock, and it is not redeemable prior to November 1, 2017 unless: (A) there is a change in control and redemption occurs pursuant to a special right of redemption related to that change in control or (B) the Closing Bid Price of our common stock has equaled or exceeded the conversion price initially set at $10.00 per share by 150% for at least 20 trading days in any 30 consecutive trading day period (a "Market Trigger");
- The redemption price is $25.00 per share plus any accrued and unpaid dividends;
- Liquidation preference is $25.00 per share plus any accrued and unpaid dividends;
- The Series C Preferred Stock is senior to all our other securities except our Series B Preferred Stock, which is senior to the Series C Preferred Stock, and ranks on parity with our Series D Preferred Stock (as defined below);

- There is a general conversion right with respect to the Series C Preferred Stock with an initial conversion price of $10.00 per share, a special conversion right upon a change in control, and a market trigger conversion at our option in the event of a Market Trigger;
- The Series C Preferred Stock has been listed on the NYSE and is registered under our universal shelf; and
- Holders of the Series C Preferred Stock have no voting rights, except: 1) as otherwise required by law; 2) with respect to any proposal to (A) create, authorize or increase the authorized or issued amount of any class or series of our equity securities which rank senior to the Series C Preferred Stock or (B) amend, alter or repeal any provision of our charter, as amended, in a manner which materially and adversely affects any right, preference, privilege or voting power of the holders of the Series C Preferred Stock; and 3) the holders of the Series C

Preferred Stock will have the right to elect two directors to our board of directors upon the occurrence of a Penalty Event.

On April 30, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of June 3, 2013, in accordance with the terms of our charter, as June 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from March 2013 through May 2013. The record date was May 15, 2013.

On July 18, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of September 3, 2013, in accordance with the terms of our charter, as September 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from June 2013 through August 2013. The record date was August 16, 2013.

On October 17, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of December 2, 2013, in accordance with the terms of our charter, as December 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from September 2013 through November 2013. The record date was November 15, 2013.

On January 28, 2014, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of March 3, 2014, in accordance with the terms of our charter, as March 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from December 2014 through February 2014. The record date was February 17, 2014.

Series D Preferred Stock

On September 30, 2013, we sold 1,000,000 shares of the Company's newly designated 10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock (the "Series D Preferred Stock"). These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated September 26, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750), which was declared effective by the SEC on September 18, 2012. The shares were offered to the public at $25.00 per share for gross proceeds of $25,000. We incurred issuance costs of $1,875, yielding net proceeds of $23,125.

On October 17, 2013, we entered into an At Market Issuance Sales Agreement ("Series D ATM Agreement") with MLV. The Series D ATM Agreement contemplates periodic sales by MLV of our Series D Preferred Stock as and when directed by the Company. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated October 17, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012. On and after October 17, 2013 through January 31, 2014, we sold 69,031 shares of our Series D Preferred Stock under the Series D ATM Agreement and a prospectus supplement at prices ranging from $23.95 to $24.38 per share. We received gross proceeds of $1,667 and incurred issuance costs of $46, yielding net proceeds of $1,621 in connection with these sales.

On January 31, 2014, pursuant to our Purchase and Sale Agreement with by and among Armstrong Cook Inlet, LLC (“Armstrong”), GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC (collectively, the “Sellers”), we issued 213,586 shares of our Series D Preferred Stock to be held in escrow for the benefit of the Sellers, valued at approximately $5,000. For purposes of determining the number of shares of the Series D Preferred Stock, it was valued on January 31, 2014 as the average of its daily volume weighted average prices for the 10 trading days ending on and including January 31, 2014. The Series D Preferred Stock was issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. The Series D Preferred Stock will be held in escrow until the transfer of the equity interests in Anchor Point Energy, LLC has been completed and certain necessary regulatory approvals have been received (see Note 15 - Subsequent Events). Pursuant to the terms of our Charter applicable to the Series D Preferred Stock, we are required to pay dividends on the Series D Preferred Stock held in escrow that are payable on any dividend payment date occurring on and after declared after March 3, 2014. The dividends are also required to be paid into escrow.

The Series D Preferred Stock is classified as permanent equity in accordance with ASC 480 and is being accreted to redemption value through the earliest redemption date of September 30, 2018, which resulted in an accretion of $139 during the nine months ended January 31, 2014. The fair value of the Series D Preferred Stock was $30,655 as of January 31, 2014, based on the closing price at that date. The designations, rights and preferences of the Series D Preferred Stock include:

- From the date of original issuance to (but not including) December 1, 2018 the holders are entitled to receive a 10.5% per annum cumulative quarterly dividend based on the $25.00 per share liquidation preference per annum, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited by making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);
- After (and including) December 1, 2018, the holders are entitled to receive a cumulative quarterly dividend at an annual rate equal to the sum of (a) Three-Month LIBOR (as defined below) as calculated on each applicable date of determination and (b) 9.073%, based on the $25.00 per share liquidation preference per annum, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited by making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);
- With respect to the Series D Preferred Stock, "Three-Month LIBOR" means: on any date of determination, the rate (expressed as a percentage per year) for deposits in U.S. dollars for a three-month period as appears on Bloomberg, L.P. page US0003M, as set by the British Bankers Association at 11:00 am (London time) on such date of determination;
- The dividend may increase by 2% to a penalty rate of (a) 12.5% (before December 1, 2018) or (b) an annual rate equal to the sum of (i) Three-Month LIBOR as calculated on each applicable date of determination and (ii)11.073%, based on the $25.00 per share liquidation preference per annum (after and including December 1, 2018) if we fail to (A) pay dividends for four or more quarterly dividend periods, whether or not consecutive, or (B) maintain the listing of our Series D Preferred Stock on a national securities exchange (the events listed in clauses (A) and (B) being "Penalty Events");
- There is no mandatory redemption or stated maturity with respect to the Series D Preferred Stock, and it is not redeemable prior to September 30, 2018 unless there is a change in control and redemption occurs pursuant to a special right of redemption related to that change in control;
- The redemption price is $25.00 per share plus any accrued and unpaid dividends;
- Liquidation preference is $25.00 per share plus any accrued and unpaid dividends;
- The Series D Preferred Stock is senior to all our other securities except our Series B Preferred Stock, which is senior to the Series D Preferred Stock, and ranks on parity with our Series C Preferred Stock;
- The Series D Preferred Stock has been listed on the NYSE and is registered under our universal shelf; and
- Holders of the Series D Preferred Stock have no voting rights, except: 1) as otherwise required by law; 2) with respect to any proposal to (A) create, authorize or increase the authorized or issued amount of any class or series of our equity securities which rank senior to the Series D Preferred Stock or (B) amend, alter or repeal any provision of our charter, as amended, in a manner which materially and adversely affects any right, preference, privilege or voting power of the holders of the Series D Preferred Stock; and 3) the holders of the Series D Preferred Stock will have the right to elect two directors to our board of directors upon the occurrence of a Penalty Event.

On October 17, 2013, our Board of Directors declared a dividend of approximately $0.44 per share on our Series D Preferred Stock which was paid on the next regularly scheduled dividend payment date of December 2, 2013, in accordance with the terms of our charter as December 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference for the Series D Preferred Stock, accruing from issuance in September 2013 through November 2013. The record date was

November 15, 2013.

On January 28, 2014, our Board of Directors declared a dividend of approximately $0.66 per share on our Series D Preferred Stock which was paid on the next regularly scheduled dividend payment date of March 3, 2014, in accordance with the terms of our charter as March 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference for the Series D Preferred Stock, accruing from issuance in December 2013 through February 2014. The record date was February 17, 2014.

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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)

11. INCOME TAXES

We have a significant deferred income tax liability related to the excess of the book carrying value of oil and gas properties over their collective income tax bases. This difference will reverse (through lower tax depletion deductions) over the remaining recoverable life of the properties, resulting in future taxable income in excess of income for financial reporting purposes. As an independent producer of domestic oil and gas, we take advantage of certain elective provisions presently in the Internal Revenue Code allowing for expensing of specified intangible drilling and development costs that are typically capitalized for book purposes. This temporary difference also reverses over the remaining life of the properties. As a result of these elections, we presently have U.S. federal and state net operating loss carryovers that are expected to be fully utilized against future taxable income resulting solely from the reversal of the temporary differences between the book carrying value of oil and gas properties and their tax bases. We are not relying on forecasts of taxable income from other sources in concluding that no valuation allowance is needed against any of our deferred tax assets. Our provision for income taxes for the third interim reporting period in fiscal 2014 is based on the actual year-to-date effective rate, as this is our best estimate of our annual effective tax rate for the full fiscal year. The computation of the annual effective tax rate includes a forecast of our estimated "ordinary" income (loss), which is our annual income (loss) from operations before tax, excluding unusual or infrequently occurring (or discrete) items. Significant management judgment is required in the projection of ordinary income (loss) in order to determine the estimated annual effective tax rate. The level of income (or loss) projected for fiscal 2014 causes an unusual relationship between income (loss) and income tax expense (benefit), with small changes resulting in: (i) a potential significant impact on the rate and, (ii) potentially unreliable estimates. As a result, we computed the provision for income taxes for the three and nine month periods ended January 31, 2014 and January 31, 2013 by applying the actual effective tax rate to the year-to-date income (loss), as permitted by GAAP. The effective tax rate for the year-to-date period ended January 31, 2014 is a benefit of (43.7%). The principal differences in our effective tax rate (benefit) for this period and the federal statutory rate of 35% are state income taxes, a favorable permanent difference related to mark-to-market accounting for Company warrants, and unfavorable permanent difference related to incentive stock options. No valuation allowance was deemed necessary in order to fully benefit the Company's year-to-date loss due to the presence of sufficient future taxable income related to the excess of book carrying value in oil and gas properties over their corresponding tax bases. No other sources of taxable income were considered by Management in reaching this conclusion. No significant cash payments of income taxes were made during the year-to-date period ended January 31, 2014, and no significant payments are expected during the succeeding 12 months.

12. ALASKA PRODUCTION TAX 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%)

We recognize a receivable when the amount of the credit is reasonably estimable and receipt is probable. For expenditure and exploration based credits, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, the credit is recorded as a reduction to the Alaska production tax. To the extent the credit amount exceeds the Alaska production tax, the credit is recorded as a reduction to general and administrative expenses.

As of January 31, 2014 and April 30, 2013, the Company has reduced the basis of capitalized assets by $43,218 and $14,547 for expenditure and exploration credits, respectively. The reductions are recorded on our condensed consolidated balance sheets in oil and gas properties and equipment. As of January 31, 2014 and April 30, 2013, the Company had outstanding net receivables from the State of Alaska in the amount of $19,763 and $12,713, respectively.

13. LITIGATION

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

This action was revived on August 4, 2011, when a breach of contract case was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled CNX Gas Company, LLC v. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC and Scott Boruff, arises from the same allegations as the previous action in the state court. The federal case seeks money damages from us for breach of contract; however, unlike the previous action, it does not seek specific performance of the assignments at issue. The Plaintiff claims that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We reached a settlement with the Plaintiff on January 24, 2014, wherein we would pay the Plaintiff $1,250 in exchange for their agreement to dismiss the case with prejudice. The Company recorded a loss of $1,250 related to this settlement in other operating expense (income), net in its consolidated statement of operations for the three and nine months ended January 31, 2014.

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 warrant and violated a duty of good faith and fair dealing. The suit seeks 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 are 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 have filed our Answer, conducted discovery and are presently awaiting further action by the plaintiff. 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 because Mr. Stafford has made no effort whatsoever to prosecute his case since April 2, 2013, has missed filing deadlines, and has failed to appear to give his deposition both times we have noticed it. 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 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 set for November 4, 2013. On October 21, 2013, the trial was postponed with no new trial date having been set. On October 31, 2013, the judge ruled on our outstanding Motion for Summary Judgment, granting it as to the unjust enrichment claim and breach of the implied covenant of good faith and fair dealing claim, and denying it as to the breach of contract claim. We expect to proceed to trial on the breach of contract claim once a new trial date is set. In February 2014, we received notice from a third party seeking to intervene in the case in order to secure payment of a debt allegedly owed by the Plaintiff to the third party. We believe this intervention would have no effect on the outcome of the case. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

In August 2011, several purported class action lawsuits were filed against us in the United States District Court for the Eastern District of Tennessee. The lawsuits made similar claims and have been consolidated into one case, styled In re Miller Energy Resources, Inc. Securities Litigation. The suit names us, along with several of our current and former executive officers, Scott Boruff, Paul Boyd, Ford Graham, David Hall, and Deloy Miller, as defendants. The Plaintiffs allege two causes of action against the defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks money damages against us and the other defendants, and payment of the Plaintiffs' attorney's fees. We have filed a Motion to Dismiss the case, which was denied on February 4, 2014 as to all defendants save Ford Graham. 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 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 alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failure to maintain internal controls; (3) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (4) Unjust Enrichment; (5) Abuse of Control; Gross Mismanagement, and; (6) Waste of Corporate Assets. The Plaintiff seeks 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. We have filed a Motion to Dismiss and, in the alternative, a Motion to Stay pending the outcome of the Class Action. The Plaintiff has agreed to stay this case awaiting a ruling on the plaintiff's appeal in the federal derivatives case in Lukas v. Miller Energy Resources, Inc., et al, as described in the next paragraph. The Plaintiff has also agreed to voluntarily dismiss the case in the event the plaintiff's appeal in Lukas is denied. On October 1, 2013, the Court entered an Order dismissing the case without prejudice on the motion of the Plaintiff. On October 24, 2013, we filed a Motion to Amend the Order of Dismissal as the agreement with the Plaintiff was that the case would be dismissed with prejudice if the Sixth Circuit Court of Appeals affirmed the dismissal of the Lukas case, which it has.

On August 25, 2011, and August 31, 2011, two derivative actions were filed against us and our Board of Directors and former Chief Financial Officer in the United States District Court for the Eastern District of Tennessee. These cases were consolidated into Patrick P. Lukas, derivatively on behalf Miller Energy Resources, Inc. v. Merrill A. McPeak, Scott M. Boruff, Deloy Miller, Jonathan S. Gross, Herman Gettelfinger, David Hall, Charles M. Stivers, Don A. Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. As noted below, this case had been dismissed by the trial court, but that dismissal was unsuccessfully appealed by the plaintiffs. It contained substantially similar claims as Valdez. The suit alleged the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (3) Unjust Enrichment; (4) Abuse of Control; (5) Gross Mismanagement, and; (5) Waste of Corporate Assets. The Plaintiffs sought unspecified money damages from the individual defendants, to have us take certain actions with respect to our management, restitution to us, and the Plaintiffs' attorney fees and costs. We filed a Motion to Dismiss, which was granted on September 21, 2012. On October 16, 2012, a notice of appeal of this dismissal was filed by the Plaintiffs with the Sixth Circuit Court of Appeals. The appeal has been fully briefed, and the Court heard oral arguments on July 24, 2013. On September 19, 2013, the Court of Appeals affirmed the judgment of the District Court dismissing the case. On October 3, 2013, the Plaintiff filed a Motion for Rehearing En Banc. We filed our response to that motion on October 21, 2013, and the Court denied the motion on January 8, 2014.

On August 31, 2012, we terminated an agreement with Voorhees Equipment and Consulting, Inc. (“Voorhees”) for the construction and sale of the rig currently being used on the Osprey Platform, Rig 35, (the “Rig 35 Agreement”). We terminated the agreement based on our belief that Voorhees was in breach of its obligations thereunder. Voorhees later indicated its desire to arbitrate claims it believes it has under invoices arising between May 29, 2012 and August 31, 2012. We believe we have grounds to dispute liability with respect to some or all of these outstanding invoices. In addition, we expect to assert counterclaims against Voorhees for damages exceeding the amounts Voorhees claims are owed to it, for breach of the relevant contract by Voorhees. The parties elected to engage a private arbitrator to settle this dispute 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 dispute is over unpaid transportation fees related to the transportation of equipment for Rig 35. These amounts were already the subject of the planned arbitration with Voorhees. As all disputes under the Rig 35 contract are subject to mandatory arbitration, we filed a motion to compel arbitration, which was granted. We are currently in settlement discussions and have postponed the arbitration as we seek a settlement. We believe that any loss would be limited to the payment of the outstanding invoices of approximately $531, plus the cost of defense.

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

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

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

14. COMMITMENTS AND CONTINGENCIES

On November 5, 2009, CIE entered into an Assignment Oversight Agreement ("AOA") with the Alaska Department of Natural Resources ("Alaska DNR") which set out certain terms under which the Alaska DNR would approve the transfer of oil and gas leases owned by the State of Alaska from Pacific Energy to CIE. This agreement remains in place following our acquisition of CIE in December 2009. Generally, the agreement requires CIE to provide the Alaska DNR with additional information and oversight authority to ensure that CIE is acting diligently to develop the oil and gas from the Redoubt Unit and West McArthur River Unit ("WMRU"). Under the terms of the AOA, until the Alaska DNR determines that CIE has completed certain development and operational commitments relating to the WMRU and Redoubt Units, CIE must do the following, in addition to the normal requirements under the terms of the leases:

- file a quarterly summary of expenditures by oil and gas field, tied to objectives in CIE's business plan and plan of development previously presented to the Alaska DNR,
- meet monthly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,
- notify the Alaska DNR 10 days prior to commitment when CIE is preparing to spend funds on a purchase, project or item relating to the WMRU or Redoubt Unit Leases of more than $5,000,
- annually submit a new plan of development for the Alaska DNR's approval.

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

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

On March 11, 2011, the Company entered into a Performance Bond Agreement under its AOA with the state of Alaska. Under the Performance Bond Agreement, the Company is required to post a total bond of $18,000 for the dismantling and abandonment of the properties. As agreed with the state of Alaska, the Performance Bond Agreement fulfills our commitment under the AOA to fund the full dismantlement costs with respect to our onshore and offshore assets. The Performance Bond Agreement also stipulated that funds held by the state in an escrow account will be credited towards the $18,000.

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Failure to submit the information required by the AOA would constitute a default under the AOA. If the default could not be cured within 30 days, the leases would be subject to termination by the Alaska DNR.

Under the terms of the Performance Bond Agreement, the Company is obligated to fund an additional $12,000 towards the bond in addition to the amount held by the state in the escrow account. As of January 31, 2014, $1,000 of this amount has been funded. The remaining $11,000 (subject to annual inflation adjustments) will be funded through annual payments as follows:

July 1, 2014	$1,500
July 1, 2015	2,000
July 1, 2016	2,500
July 1, 2017	2,000
July 1, 2018	1,500
July 1, 2019	1,500
	$11,000

15. SUBSEQUENT EVENTS

Repayment of MEI Loans

On February 3, 2014, we repaid all obligations under the First Secured Promissory Note dated as of November 1, 2009, a Second Secured Promissory Note dated as of December 15, 2009, a Third Secured Promissory Note dated as of May 15, 2010, and a Loan and Security Agreement dated as of March 19, 2010 (as amended, supplemented or otherwise modified prior to the date hereof, the "MEI Loan Documents"), by and among Miller Energy Income 2009-A, LP, a Delaware limited partnership ("MEI") and us. The MEI Loan Documents have terminated.

Prepayment of Prior Credit Facility

On February 3, 2014, we repaid in full the loans outstanding under the Prior Loan Agreement with Apollo, as administrative agent and lender, as amended from time to time, which provided for a credit facility of up to $100,000 (the "Prior Credit Facility") with a borrowing base of $55,000 and an Additional Availability allowing for $20,000 in loans. The availability under the Prior Credit Facility had been fully drawn by us. The terms of the Prior Credit Facility were amended and restated in their entirety in connection with New Credit Facility described below and, except to the extent incorporated into the New Credit Facility, the terms of the Prior Credit Facility are superseded and without further effect.

As a result of the prepayment of the Prior Credit Facility, we owed Apollo a prepayment and extension fee of $9,223 (the “Prepayment Fee”) in connection with the termination and early repayment of borrowings under the Prior Credit Facility. Pursuant to a letter agreement entered into by the Company and Apollo, the Prepayment Fee shall be paid to Apollo in four equal installments of approximately $2,306 on the last day of each calendar quarter, commencing June 30, 2014.

Amendment and Restatement of Prior Credit Facility

On February 3, 2014, (the "Closing Date"), we entered into New Loan Agreement, among us, as borrower, Apollo, as administrative agent and the lenders from time to time party thereto.

The New Loan Agreement provides for a $175,000 term credit facility (the "New Credit Facility"), all of which was made available to and drawn by us on the Closing Date. The amounts drawn were subject to a 2% original issue discount. Amounts outstanding under the New Credit Facility bear interest at a rate of LIBOR plus 9.75%, subject to a 2% LIBOR floor. The New Credit Facility permits us to enter into a reserve-based revolving credit facility of up to

$100,000 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 New Credit Facility will become a second-lien credit facility. The New Credit Facility carries a four year maturity, which may be extended by up to an additional year as necessary so that it matures at least six months after the maturity date of the first lien revolving credit facility, if put in place. The New Credit Facility contains customary second lien covenants, including a leverage ratio, interest coverage ratio, current ratio, asset coverage ratio, minimum gross production and change of management control covenants. Subject to certain conditions contained in the New Loan Agreement, the New Credit Facility also allows for us to implement a discretionary share repurchase plan on terms and conditions reasonably satisfactory to the Administrative Agent and the Lenders.

The New Loan Agreement contemplates and allows us to seek and put in place a new, first priority, credit facility ranking senior to the New Credit Facility (a "Future Credit Facility") subject to certain terms and conditions set forth in the New Loan Agreement.

We used $75,300 of the proceeds drawn under the New Credit Facility to refinance the Prior Credit Facility with Apollo and $56,975 to finance the acquisition of the North Fork Unit (as described below). In addition, $3,800 was used to retire the obligations owed under the MEI Loan Documents. The remainder of the proceeds from the New Credit Facility will be used for general corporate purposes.

On the Closing Date, in connection with the New Credit Facility, we, along with all of our consolidated subsidiaries (other than MEI), entered into an Amended and Restated Guarantee and Collateral Agreement (the "Guarantee") with Apollo, for the benefit of the lenders from time to time party to the New Loan Agreement. Under the terms of the Guarantee and related security documents each of our consolidated subsidiaries (other than MEI) have guaranteed our obligations under the New 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 New Credit Facility.

The foregoing description is qualified in its entirety by reference to the full text of the New Loan Agreement which was filed as Exhibit 10.01 to a Current Report on Form 8-K on February 6, 2014 and the Guarantee and Collateral Agreement which was filed as Exhibit 10.02 thereto.

North Fork Unit Acquisition Agreement

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

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

The purchase of both the North Fork Properties and Anchor Point Equity will be accounted for as required by ASC 850, "Business Combinations." Under ASC 805, we are required to allocate the purchase price to tangible and identifiable intangible assets acquired and liabilities assumed based on their fair values at the respective closing dates. Any excess of the purchase price over those fair values is recorded as goodwill. We are in the process of valuing the assets acquired and liabilities assumed in the North Fork Properties acquisition. Disclosures required by ASC 805 will be provided when the initial accounting for the acquisitions is complete.

Payment of Dividends

On March 3, 2014, we paid a semiannual dividend of approximately $5.95 per share on the Series B Preferred Stock. The dividend payment is equivalent to an annualized yield of 12% per share, based on the $100.00 per share stated liquidation preference, accruing from September 1, 2013 through February 28, 2014. The record date was February 17, 2014.

On March 3, 2014, we paid a quarterly dividend of approximately $0.67 per share on the Series C Preferred Stock. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference, accruing from December 1, 2013 through February 28, 2014. The record date was February 17, 2014.

On March 3, 2014, we paid a quarterly dividend of approximately $0.66 per share on the Series D Preferred Stock. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference, accruing from issuance in December 1, 2013 through February 28, 2014. The record date was February 17, 2014.

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Series D Preferred Stock

Pursuant to our Series D ATM Agreement with MLV, between January 31, 2014 and March 5, 2014, we offered and sold an additional 1,417 shares of our Series D Preferred Stock, at a price of $24.00 per share. We received gross proceeds of $34 and incurred issuance costs of $1, yielding net proceeds of $33. These securities are registered for sale to the public pursuant to a prospectus, dated September 19, 2012, a prospectus supplement dated October 17, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

Appointment of John M. Brawley as Chief Financial Officer

On February 12, 2014, our Board of Directors appointed Mr. John Brawley, 31, as our Chief Financial Officer. Mr. Brawley, through his consulting company, was previously a consultant for us, starting in November 2013. From 2010 to 2013 Mr. Brawley worked for Guggenheim Partners, LLC, a diversified asset management firm, where he oversaw their mezzanine energy portfolio as the co-head of the Houston office and provided energy expertise for Guggenheim's high yield and syndicated loan portfolios. Prior to Guggenheim Partners, LLC, Mr. Brawley worked directly for the CFO of ATP Oil & Gas as a consultant from 2006 to 2010, and was a financial analyst at Lehman Brothers in their energy investment banking practice in 2006. Mr. Brawley received a B.A. in Economics and Biological Sciences and an M.B.A, with a concentration in Accounting and Finance, from Rice University.

We entered into an employment agreement with Mr. Brawley, dated as of February 12, 2014, extending until November 12, 2016, under which Mr. Brawley will receive an annual salary of $350. The Board also granted Mr. Brawley 35,000 shares of restricted stock contingent on a shareholder approval of an increase in the number of shares available under the 2011 Equity Compensation Plan (the "2011 Plan") adequate to cover this grant of restricted stock. In addition, in connection with Mr. Brawley’s engagement as a consultant on November 12, 2013, the Compensation Committee previously granted an option (the “Option”) to purchase 800,000 shares of our common stock, vesting as follows: 300,000 shares vesting on May 12, 2014, 250,000 shares vesting on November 12, 2015, and 250,000 shares vesting on November 12, 2016. This Option is also contingent upon shareholder approval of an increase in the number of shares available under the 2011 Plan adequate to cover the grant of the Option. As the Option was previously granted to Mr. Brawley’s consulting company in connection with his consulting work, that Option is being assigned with the consent of our Board of Directors and the Compensation Committee of the Board. The Option’s strike price is $6.11 per share, which was the closing price of our common stock on the New York Stock Exchange on November 12, 2013, which was when the Committee granted the Option as well as the date Mr. Brawley began rendering consulting services to us.

Also on February 12, 2014, the Company's Board of Directors approved a change in title for Mr. David J. Voyticky to President as he had previously held the title of President and Acting Chief Financial Officer.

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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.

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, 2013, and may make other forward-looking statements from time to time in other public filings, press releases and discussions with our management. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should" or similar expressions or variations on such expressions. For these statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that our expectations will prove to be correct. We undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.
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 15, 2013 and further amended on August 28, 2013. 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.

Executive Overview

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

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

- Develop Acquired Acreage. We are focused on organically growing production through drilling for our own benefit on existing leases and acreage in the exploration licenses with a view towards retaining the majority of working interest in the new wells. This strategy allows us to maintain operational control, which we believe will translate to long-term benefits;
- Increase Production. We are increasing oil and gas production through the maintenance, repair and optimization of wells located in the Cook Inlet region and development of wells in the Appalachian region of east Tennessee. Our

operational team employs a combination of the latest available technologies along with tried and true technologies to restore as well as explore and develop our properties;

- Expand Our Revenue Stream. We intend to fully exploit our mid-stream facilities, such as our injection wells and the Kustatan Production Facility, our ability to engage in the commercial disposal of waste generated by oil and gas operations, and our capacity to process third party fluids and natural gas and, when available, to offer excess electrical power to net users in the Cook Inlet region; and
- Pursue Strategic Acquisitions. We have significantly increased our oil and gas properties through strategic low-cost / high-value acquisitions. Under the same strategy, our management team continues to seek opportunities that meet our criteria for risk, reward, rate of return and growth potential. We pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

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Our management team is focused on maintaining the financial flexibility required to successfully execute these core strategies.
Our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing current reserves and economically finding, acquiring and developing additional recoverable reserves. We may not be able to find, acquire or develop 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 are focused on adding reserves through new drilling and 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 raised from sales of our Series C Preferred Stock made in "at-the-market" and "follow-on" public offerings, along with the initial public offering and "at-the-market" offerings of our Series D Preferred Stock, to support our capital expenditures during our third quarter of fiscal 2014. For the nine-month period ended January 31, 2014, we reported notable achievements in several key areas. Highlights for the period include:

- Starting May 1, 2013, and periodically during the nine month period, we issued 780,067 shares of our Series C Preferred Stock in "at-the-market" offerings pursuant to the Series C ATM Agreement and a prospectus supplement dated October 12, 2012 (issued under our existing S-3 registration statement, filed with the SEC as file number 333-183750). These sales were made at an average price on the date of such sale ranging from $21.48 to $26.71 per share. We received net proceeds of $17,090 in connection with these sales.
- On May 10, 2013, we issued 500,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated May 7, 2013 and we received net proceeds of $10,320.
- Effective May 15, 2013, we entered into a new commercial gas sales agreement in the Cook Inlet region with Chugach Electric Association, Inc., Alaska's largest electric utility. Contractual gas sales commenced during the month of May and have continued throughout the period. We have primarily delivered gas on the new agreement with production from the RU-3 and RU-4A wells in the Redoubt Shoals field.
- On June 19, 2013, we began drilling our Sword #1 well from our West McArthur River Production Facility in the Cook Inlet region. The Sword #1 well was completed as an extended reach well drilled directionally to approximately 19,000 feet in an adjacent fault block to the West McArthur River Field. The 3D seismic data shows a faulted four-way closure and an estimated 240-acre structure with an estimated ultimate recovery ("EUR") of approximately 800,000 barrels of oil from the Sword #1 well.
- On June 20, 2013, we brought a new oil well, RU-2A, into production. This well is a sidetrack of a previously producing oil well, RU-2. After clearing the well of drilling fluids from the sidetrack, a subsequent well test showed an initial production of 1,281 barrels of oil per day with a water cut of 19%. The rate of production has averaged 1,055 barrels of oil per day through January 31, 2014.
- On July 2, 2013, we issued 335,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated June 27, 2013 and we received net proceeds of $6,655.
- On July 22, 2013, we announced that our Board of Directors appointed David M. Hall to Chief Operating Officer ("COO"). Mr. Hall has been the Chief Executive Officer of our wholly-owned Alaskan operating subsidiary, Cook Inlet Energy, since 2009 and will continue in that capacity. In his new role as COO, Mr. Hall will oversee our drilling operations in both Alaska and Tennessee.
- On July 25, 2013, we elected Marceau Schlumberger to our board of Directors. Mr. Schlumberger is Miller's sixth independent director. Mr. Schlumberger has nearly twenty years of investment banking experience, including international and domestic mergers and acquisitions, restructuring, strategic analysis, and financial experience.
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On August 5, 2013, we entered into the Sixth Amendment to our Prior Credit Facility which allowed us to borrow an additional $20,000 at a temporarily reduced interest rate of 9%. For additional information on the Sixth Amendment and the Prior Credit Facility, refer to Note 7 - Debt.

- On August 17, 2013, we successfully brought our RU-1A oil well online. The well is a sidetrack of a previously producing oil well, RU-1. The newly completed well displayed an initial production rate of 700 barrels of oil per day and an approximate water cut of 5%. The rate of production has averaged 594 barrels of oil per day through January 31, 2014.
- On September 30, 2013, we completed our public offering of our Series D Preferred Stock, issuing 1,000,000 shares at $25.00 per share with net proceeds of $23,125.

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- On September 30, 2013, we completed negotiations for a multi-year gas sales agreement with Chugach Electric Association, Inc., which expanded upon the short-term contract signed in May. The contract was submitted to the Regulatory Commission of Alaska and was approved on November 25, 2013.
- On October 12, 2013, we brought our RU-5B oil well online. The rate of production has averaged 186 barrels of oil per day through January 31, 2014.
- On October 15, 2013, we brought our Brimstone H-1 well online in Tennessee. Similar to our other horizontal wells, this well requires additional testing. At January 31, 2014, the well had produced 2,982 bbls of oil.
- On October 23, 2013, we reached total depth on our Sword #1 well. On November 20, 2013, we brought the well online. Its initial production rate was 883 bopd. At January 31, 2014, the well was producing approximately 660 bopd.
- On October 24, 2013, we received an Underground Injection Control ("UIC") permit from the Environmental Protection Agency ("EPA"). We intend to re-inject gas into a vertical well adjacent to our CPP H-1 horizontal well in Tennessee to maintain reservoir pressure and hopefully increase production.
- On October 31, 2013, we completed our workover of the RU-D1 disposal well to prepare for additional drilling activity on the Osprey platform.
- On November 1, 2013, the Susitna Basin Exploration License #2 ("Susitna #2 License") expired. Prior to expiration, we received confirmation from the State of Alaska that we had met our work commitment under the Susitna #2 License and were eligible to convert acreage under the license to leases. We applied for conversion and requested issuance of the proposed leases in three groups. The first group of leases consisting of a total of 47,000 acres were issued with an effective date of November 1, 2013. The second and third group of leases consisting of a total of 120,900 acres were issued with an effective date of January 1, 2014. Upon award, an annual rental fee of $3.00 per acre was paid to the State of Alaska. The annual rental fee for all three groups of leases totals $504.
- On November 22, 2013, we entered into an agreement to acquire the North Fork Properties and the Anchor Point Equity in the Cook Inlet region for $64,975, with $5,000 to be paid in our Series D Preferred Stock.
- Beginning November 26, 2013 and periodically thereafter, we issued 69,031 shares of our Series D Preferred Stock in "at-the-market" offerings pursuant to the Series D ATM Agreement and a prospectus supplement dated October 17, 2013 (issued under our existing S-3 registration statement filed with the SEC as file number 333-183750). These sales were made at an average price ranging from $24.00 to $24.38 per share. We received net proceeds of $1,621 in connection with these sales.
- On November 28, 2013, we spudded our WMRU-8 oil well from our West McArthur River Production Facility. WMRU-8 was drilled as a directional well into a separate fault block to the main producing structure in the West McArthur River Field. The well reached a total depth of 15,536 feet on February 12, 2014 after successfully drilling and logging the Jurassic and West Forelands secondary targets. The well is currently being completed in the Hemlock formation.

On February 3, 2014, we entered into a New Loan Agreement with Apollo Investment Corporation, as administrative agent. Proceeds from the new $175,000 term credit facility were used to repay the previously existing credit facility, repay all obligations to Miller Energy Income 2009-A, LP, acquire the North Fork Properties and provide working capital (see Note 15 - Subsequent Events).
On February 6, 2014, we entered into the Trans-Foreland Pipeline Development Agreement with Tesoro Alaska Company (“Tesoro”) and Trans-Foreland Pipeline Company, LLC (“TFPC”). The agreement allows for the construction of the Trans-Foreland Pipeline to connect our Kustatan Production Facility on the west side of the Cook Inlet to the Kenai Pipe Line Company tank farm of the east side. Completion of the pipeline would provide numerous advantages to us, including reduced transportation cost and delays.
On February 12, 2014, our Board of Directors appointed John M. Brawley as our Chief Financial Officer. In addition, the Board of Directors approved a change in the title of David J. Voyticky to President, as he previously held the title of President and Acting Chief Financial Officer.

Fiscal 2014 Outlook

As we head into the final quarter of fiscal 2014, we believe our inventory of recompletion, workovers, exploration and development projects and newly acquired assets offer numerous growth opportunities. We are in the process of drilling our WMRU-8 onshore oil well, and are completing preparatory work to begin drilling our RU-9 offshore oil well. We continue to work on proving the horizontal well concept in Tennessee and expect to make significant progress now that we have received a gas reinjection permit from the EPA, which is crucial to our plans to optimize our CPP H-1 well. We have several additional development projects planned, which we expect will contribute to our production in fiscal 2014. No assurance can be made

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regarding the success of these development and recompletion efforts. Our current fiscal 2014 capital budget approved by our Board of Directors is $297,000. The majority of this budget is expected to be spent on projects in Alaska, with the remaining amount allocated to our Appalachian region. We expect to spend approximately $200,000 of our approved capital budget during fiscal 2014. Due to the uncertainty associated with changes in commodity prices, we closely monitor our cost levels and revise our capital budgets based on changes in forecasted cash flows. This means our plan for capital expenditures may change as a result of anticipated changes in the market place. Further, our ability to fully utilize the budget will be dependent on a number of factors including, but not limited to, access to capital, favorable weather and regulatory approval.
Although we expect to sell our Series C and Series D Preferred Stock in "at-the-market" offerings during fiscal 2014, we cannot guarantee that market conditions will continue to permit such sales at prices we would find acceptable. If market conditions are unfavorable, cash generated from those offerings would not be available to us.

Significant Operational Factors

- Realized Prices: Our average realized oil price for the three and nine months ended January 31, 2014 was $94.58 and $100.16, respectively, as compared to $98.77 and $101.42, respectively, for the same periods in the prior year. These results exclude the impact of commodity derivative settlements.
- Production: Our net production, excluding fuel gas, for the three and nine months ended January 31, 2014 was 225,377 boe and 543,717 boe as compared to 82,327 boe and 237,552 boe, respectively, for the same periods in the prior year.
- Capital Expenditures and Drilling Results: During the three and nine months ended January 31, 2014, we paid $28,253 and $95,374, respectively, in capital expenditures.

We experience earnings volatility as a result of not using hedge accounting for our crude oil commodity derivatives, which are used to hedge our exposure to changes in commodity prices. This accounting treatment can cause earnings volatility as the positions of future crude oil production are marked-to-market. The non-cash gains or losses are included on our condensed consolidated statement of operations until the derivatives are cash settled as the commodities are produced and sold. We do not enter into speculative trading positions and we only use commodity derivatives to lock in the future sales price for a portion of our expected crude oil production.

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Results of Operations

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

	For the Three Months Ended January 31, 2014	2013	$ Variance	% Variance
Oil revenues:				
Cook Inlet	$15,717	$6,342	$9,375	148 %
Appalachian region	631	378	253	67
Total	$16,348	$6,720	$9,628	143
Natural gas revenues:				
Cook Inlet	$28	$13	$15	115
Appalachian region	90	120	(30)	(25)
Total	$118	$133	$(15)	(11)
Other revenues:				
Cook Inlet	$7	$1,036	$(1,029)	(99)
Appalachian region	155	110	45	41
Total	$162	$1,146	$(984)	(86)
Total revenues	$16,628	$7,999	$8,629	108 %

Net Production

	For the Three Months Ended January 31, 2014	2013	Variance	% Variance
Oil volume - bbls:				
Cook Inlet	212,441	71,700	140,741	196 %
Appalachian region	6,981	4,062	2,919	72
Total	219,422	75,762	143,660	190
Natural gas volume[1]- mcf:				
Cook Inlet	5,277	7,588	(2,311)	(30)
Appalachian region	30,450	31,799	(1,349)	(4)
Total	35,727	39,387	(3,660)	(9)
Total production[2] - boe:				
Cook Inlet	213,321	72,965	140,356	192
Appalachian region	12,056	9,362	2,694	29
Total	225,377	82,327	143,050	174 %

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

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

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Pricing

Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to the rise in global demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in the third quarter of 2014 were 4% below the same period last year. For the three months ended January 31, 2014, realized oil prices averaged $94.58 per bbl, compared with $98.77 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 2014 decreased over the same period last year. For the three months ended January 31, 2014, realized natural gas prices averaged $3.39 per mcf, compared with $3.86 per mcf for the same period in the prior year. The decrease in the averaged realized gas prices resulted from a decrease in gas sold in Alaska under our new natural gas sales contract in the Cook Inlet region which provides for a contract price of $6.00 per mcf.

Oil Revenues

During the third quarter of fiscal 2014 oil revenues totaled $16,348, which represents a 143% increase over the same period in the prior year. Oil revenues represented 98% of our third quarter consolidated total revenues. Net barrels sold for the current period was 172,856, which represents a 103,777 bbl, or 150%, increase as compared to the same period last year. The increase in barrels sold was partially offset by a 4% decrease in realized oil prices.

The increase in net barrels sold results from an increase in oil production for the period. Oil production increased 143,660 bbls, or 190%, to 219,422 bbls. The increase was driven by a 140,741 bbl increase in the Cook Inlet region and a 2,919 bbl increase in the Appalachian region. The production increase in the Cook Inlet region resulted from RU-1A, RU-2A and RU-5B in our Redoubt Shoals field and our new Sword #1 well being on line during the three months ended January 31, 2014. The production increase in the Appalachian region is a result of new production from our CPP H-1 and Brimstone H-1 wells.

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

	For the Three Months Ended January 31, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	29,433	17,357	46,790
Gross production	254,211	14,330	268,541
Gross sales	(197,717)	(13,734)	(211,451)
Pipeline adjustments	153	—	153
Ending inventory balance	86,080	17,953	104,033
Net change in inventory	56,647	596	57,243

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

Natural Gas Revenues
During the third quarter of fiscal 2014, natural gas revenues totaled $118, which was 11% lower than the same period in the prior year. The decline resulted from a combination of a 12% decrease in average realized prices and a 9% decrease in production. Natural gas represented 1% of our third quarter consolidated total revenues. The following summarizes our natural gas sales and production activity during the current period.

	For the Three Months Ended January 31, 2014		
	Cook Inlet	Appalachian	Total
Natural gas production - mcf:			
Gross gas produced	239,639	68,601	308,240
Net gas produced	238,603	30,450	269,053
Fuel gas used	233,326	—	233,326
Natural gas sales - mcf:			
Gross gas sold	6,313	67,807	74,120
Net gas sold	5,277	29,656	34,933

Other Revenues
Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling, maintenance and repair of third party wells as well as rental income we receive for services and use of facilities in the Cook Inlet region. During the third quarters of fiscal 2014 and 2013, other revenues totaled $162 and $1,146, respectively. The decrease resulted from lower revenue from our grind and inject facility which allows for the processing and safe disposal of solid material that is extracted as a byproduct of drilling wells, coupled with having revenue from a road building contract in the same period last year. The decline is primarily a result of additional revenue in 2013 from a completed road building contract and limited activity from other projects in the current period.

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

	For the Three Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Oil and gas operating costs	$5,821	$4,118	$1,703	41 %
Cost of other revenues	256	1,051	(795)	(76)
General and administrative	7,587	5,518	2,069	37
Exploration expense	352	187	165	88
Depreciation, depletion and amortization	7,642	3,341	4,301	129
Accretion of asset retirement obligation	305	284	21	7
Other operating expense, net	1,250	—	1,250	(100)
Total costs and expenses	$23,213	$14,499	$8,714	60 %

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

Oil and Gas Operating Costs

The table below presents a comparison of our oil and gas operating costs for the three months ended January 31, 2014 and 2013.

	For the Three Months Ended January 31, 2014	2013	$ Variance	% Variance
Third party transportation costs	$1,411	$563	$848	151 %
Lease operating expense	4,410	3,555	855	24
Total oil and gas operating costs	$5,821	$4,118	$1,703	41 %

Lease operating expense	$4,410	$3,555
Costs allocated to inventory	1,114	(215)
Gross production costs	5,524	3,340
Gross oil and gas produced - boe	319,914	115,731
Lease operating expense per boe produced	$17.27	$28.86

Oil and gas operating costs increased $1,703 from third quarter fiscal 2013, or 41%. The increase in oil and gas operating costs is primarily attributable to increased production. The increased production creates additional labor and camp facility costs, well maintenance and transportation costs. The majority of our production costs are fixed. For the three months ended January 31, 2014 our lease operating expense per boe was $17.27 per bbl as compared to $28.86 per bbl in the same period last year. We expect our lease operating expense per boe produced to continue to decline as production increases.

Cost of Other Revenues

Our business is primarily focused on exploration and production activities. The cost of other revenues represent costs of services to third parties as a result of excess capacity and are derived from the direct labor costs of employees associated with these services, as well as costs associated with equipment, parts and repairs. During the third quarter of fiscal 2014, we experienced decreases in the cost of other revenues in the Cook Inlet region as we had limited projects during the period.

	For the Three Months Ended January 31, 2014	2013	$ Variance	% Variance
Direct labor	$153	$466	$(313)	(67)%
Equipment	24	397	(373)	(94)
Repairs	67	74	(7)	(9)
Insurance	—	36	(36)	(100)
Other	12	78	(66)	(85)
Total	$256	$1,051	$(795)	(76)%

(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,			
	2014	2013	$ Variance	% Variance
Salaries	$1,551	$966	$585	61 %
Professional fees	2,768	802	1,966	245
Travel	502	413	89	22
Employee benefits	609	304	305	100
Stock-based compensation	1,440	2,652	(1,212)	(46)
Other	717	381	336	88
Total	$7,587	$5,518	$2,069	37 %

G&A expenses increased $2,069 from third quarter fiscal 2013, or 37%. Salaries increased 61% from the same period in the prior fiscal year due to additions to our engineering and support staff in the Cook Inlet region, and as a result of salary increases of our named executive officers effective as of July 17, 2013. Professional fees increased 245% over the same period last year due to an increase in accounting, capital-raising, legal and investor relations activities during the quarter. Stock-based compensation declined 46% due to the expense associated with fully vested awards exceeding the expense associated with newly granted awards. During the third quarter of fiscal 2014, our Compensation Committee approved an additional grant of 800,000 options to purchase our common stock which are contingent upon shareholder approval of an increase in the number of shares available under the 2011 share-based compensation plan. We will recognize stock-based compensation upon shareholder approval.

Exploration Expense

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.

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,			
	2014	2013	$ Variance	% Variance
Depletion:				
Cook Inlet region	$6,411	$2,141	$4,270	199 %
Appalachian region	215	199	16	8
	6,626	2,340	4,286	183
Depreciation:				
Cook Inlet region	119	60	59	98
Appalachian region	897	941	(44)	(5)
	1,016	1,001	15	1
Total DD&A	$7,642	$3,341	$4,301	129 %

The increase in DD&A is primarily a result of increased production from the Cook Inlet region during the three months ended January 31, 2014.

Other Operating Expense

During the third quarter of fiscal 2014, we recorded a loss for an estimated settlement in the amount of $1,250 related to the CNX lawsuit settlement, (see Note 13 - Litigation).

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

Other Income and Expense

The following table shows the components of other income and expense for the third quarters indicated.

	For the Three Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Interest expense, net	$(407)	$(1,117)	$(710)	(64)%
Gain (loss) on derivatives, net	1,677	(1,681)	(3,358)	(200)
Other income, net	42	25	(17)	(68)
Total	$1,312	$(2,773)	$(4,085)	(147)%

Interest Expense, Net

Interest expense, net, decreased $710 from the third quarter of fiscal 2013, or 64%. The decrease in interest expense resulted from an increase in the percentage of interest expense that could be capitalized on self-constructed assets.

Gain (Loss) on Derivatives, Net

We experience earnings volatility as a result of not using hedge accounting to account for changes in commodity prices. As the positions used to hedge future oil production are marked-to-market, both realized and unrealized gains or losses are included on our condensed consolidated statements of operations. We do not engage in speculative trading and utilize commodity derivatives only as a mechanism to lock in future prices for a portion of our expected crude oil production.

During the third quarter of fiscal 2014, we recorded a $1,677 gain on derivatives, as compared to a $1,681 loss on derivatives in the third quarter of fiscal 2013.

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

Results of Operations

Nine Months Ended January 31, 2014 Compared to Nine Months Ended January 31, 2013
Revenues

	For the Nine Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Oil revenues:				
Cook Inlet	$45,117	$21,153	$23,964	113 %
Appalachian region	1,895	1,157	738	64
Total	$47,012	$22,310	$24,702	111
Natural gas revenues:				
Cook Inlet	$380	$41	$339	827
Appalachian region	291	287	4	1
Total	$671	$328	$343	105
Other revenues:				
Cook Inlet	$141	$3,835	$(3,694)	(96)
Appalachian region	608	598	10	2
Total	$749	$4,433	$(3,684)	(83)
Total revenues	$48,432	$27,071	$21,361	79 %

Net Production

	For the Nine Months Ended January 31,			
	2014	2013	Variance	% Variance
Oil volume - bbls:				
Cook Inlet	496,349	206,290	290,059	141 %
Appalachian region	19,789	12,404	7,385	60
Total	516,138	218,694	297,444	136
Natural gas volume[1] - mcf:				
Cook Inlet	77,928	14,513	63,415	437
Appalachian region	87,547	98,630	(11,083)	(11)
Total	165,475	113,143	52,332	46
Total production[2] - boe:				
Cook Inlet	509,337	208,709	300,628	144
Appalachian region	34,380	28,843	5,537	19
Total	543,717	237,552	306,165	129 %

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

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

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

Pricing

Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to the rise in global demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in the first nine months of 2014 were 1% below the same period last year. For the nine months ended January 31, 2014, realized oil prices averaged $100.16 per bbl, compared with $101.42 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 2014 were substantially higher than the same period last year. For the nine months ended January 31, 2014, realized natural gas prices averaged $4.06 per mcf, compared with $3.06 per mcf for the same period in the prior year. The increase in the averaged realized gas prices resulted from our new natural gas sales contract in the Cook Inlet region which provides for a contract price of $6.00 per mcf.

Oil Revenues

During the first nine months of fiscal 2014, oil revenues totaled $47,012, which represents a 111% increase over the same period in the prior year. Oil revenues represented 97% of our nine month consolidated total revenues. Net barrels sold for the current period was 469,387, which represents a 260,866 bbl, or 125%, increase as compared to the same period last year. The increase in barrels sold was partially offset by a 1% decrease in realized oil prices.

The increase in net barrels sold results from an increase in oil production for the period. Oil production increased 297,444 bbls, or 136%, to 516,138 bbls. The increase was driven by a 290,059 bbls increase in the Cook Inlet region and a 7,385 bbls increase in the Appalachian region. The production increase in the Cook Inlet region resulted from RU-1A, RU-2A and RU-5B in our Redoubt Shoals field and our new Sword #1 well being on line during the nine months ended January 31, 2014. The production increase in the Appalachian region is a result of new production from our CPP H-1 and Brimstone H-1 wells.

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

	For the Nine Months Ended January 31, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	30,130	24,063	54,193
Gross production	595,082	37,953	633,035
Gross sales	(537,782)	(44,063)	(581,845)
Pipeline adjustments	(1,350)	—	(1,350)
Ending inventory balance	86,080	17,953	104,033
Net change in inventory	55,950	(6,110)	49,840

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

Natural Gas Revenues

During the first nine months of fiscal 2014, natural gas revenues totaled $671, which was 105% higher than the same period in the prior year. The increase resulted from a combination of a 33% increase in average realized prices and a 46% increase in production. The increase in the averaged realized gas prices resulted from our new natural gas sales contract in the Cook Inlet region. The increase in natural gas production resulted from selling natural gas in excess of our fuel gas needs from our RU-3 and RU-4A wells in the Cook Inlet region. Natural gas represented 1% of our consolidated total revenues for the nine month period. The following summarizes our natural gas sales and production activity during the current period.

	For the Nine Months Ended January 31, 2014		
	Cook Inlet	Appalachian	Total
Natural gas production - mcf:			
Gross gas produced	766,145	195,439	961,584
Net gas produced	750,850	87,547	838,397
Fuel gas used	672,922	—	672,922
Natural gas sales - mcf:			
Gross gas sold	93,223	195,439	288,662
Net gas sold	77,928	87,547	165,475

Other Revenues

Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling, maintenance and repair of third party wells as well as rental income we receive for services and use of facilities in the Cook Inlet region. During the first nine months of fiscal 2014 and 2013, other revenues totaled $749 and $4,433, respectively. The decline is primarily a result of additional revenue in 2013 from a completed road building contract and limited activity from other projects during the current period.

Cost and Expenses

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

	For the Nine Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Oil and gas operating costs	$18,249	$12,963	$5,286	41 %
Cost of other revenues	844	4,084	(3,240)	(79)
General and administrative	21,092	17,056	4,036	24
Exploration expense	786	244	542	222
Depreciation, depletion and amortization	22,352	9,528	12,824	135
Accretion of asset retirement obligation	903	853	50	6
Other operating expense (income), net	1,250	(65)	1,315	(2,023)
Total costs and expenses	$65,476	$44,663	$20,813	47 %

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

Oil and Gas Operating Costs

The table below presents a comparison of our oil and gas operating costs for the nine months ended January 31, 2014 and 2013:

	For the Nine Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Third party transportation costs	$3,023	$2,011	$1,012	50 %
Lease operating expense	15,226	10,952	4,274	39
Total oil and gas operating costs	$18,249	$12,963	$5,286	41 %

Lease operating expense	$15,226	$10,952
Costs allocated to inventory	(378)	114
Gross production costs	14,848	11,066
Gross oil and gas produced - boe	793,299	334,972
Lease operating expense per boe produced	$18.72	$33.04

Oil and gas operating costs increased $5,286 from the first nine months of fiscal 2013, or 41%. The increased oil and gas operating costs are primarily attributable to increased production. The increased production creates additional labor and camp facility costs, well maintenance and transportation costs. The majority of our production costs are fixed. For the nine months ended January 31, 2014 our lease operating expense per boe produced was $18.72 as compared to $33.04 in the same period last year. We expect our lease operating expense per boe produced to continue to decline as production increases.

Cost of Other Revenues

Our business is primarily focused on exploration and production activities. The cost of other revenues represent costs of services to third parties as a result of excess capacity and are derived from the direct labor costs of employees associated with these services, as well as costs associated with equipment, parts and repairs. During the first nine months of fiscal 2014, we experienced decreases in the cost of other revenues in the Cook Inlet region as we had limited projects during the period.

	For the Nine Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Direct labor	$458	$2,776	$(2,318)	(84)%
Equipment	99	709	(610)	(86)
Repairs	253	402	(149)	(37)
Insurance	—	91	(91)	(100)
Other	34	106	(72)	(68)
Total	$844	$4,084	$(3,240)	(79)%

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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,			
	2014	2013	$ Variance	% Variance
Salaries	$3,927	$2,749	$1,178	43 %
Professional fees	6,920	3,617	3,303	91
Travel	1,488	1,261	227	18
Employee benefits	1,433	735	698	95
Stock-based compensation	4,820	7,367	(2,547)	(35)
Other	2,504	1,327	1,177	89
Total	$21,092	$17,056	$4,036	24 %

G&A expenses increased $4,036 from the first nine months of fiscal 2013, or 24%. Salaries increased 43% from the same period in the prior fiscal year due to additions to our engineering and support staff in the Cook Inlet region, and as a result of salary increases for our named executive officers effective as of July 17, 2013. Professional fees increased 91% over the same period last year due to an increase in accounting, capital-raising, legal and investor relations activities during the period. Stock-based compensation declined 35% due to the expense associated with fully vested awards exceeding the expense associated with newly granted awards. During the nine months of fiscal 2014, our Compensation Committee approved an additional grant of 391,000 shares of restricted stock and 8,129,996 options to purchase our common stock which are contingent upon shareholder approval of an increase in the number of shares available under the 2011 share-based compensation plan. We will recognize stock-based compensation upon shareholder approval. On March 10, 2014, certain officers entered into an amendment to their employment agreements with the Company under which the 7,299,996 options to purchase shares of our common stock will no longer be granted (see Note 9 - Stock-Based Compensation). The increase in other expense resulted from an increase in liability insurance premiums due to our increased drilling activities and an increase in office rent related to the addition of office space in both the Cook Inlet and Appalachian regions.

Exploration Expense

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.

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 Nine Months Ended January 31,			
	2014	2013	$ Variance	% Variance
Depletion:				
Cook Inlet region	$18,405	$6,601	$	