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

FORM 10-Q

(Mark One)

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

For the quarterly period ended November 30, 2014

OR

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

For the transition period from ______________ to _______________

Commission File Number: 000-50107

DAYBREAK OIL AND GAS, INC.

(Exact name of registrant as specified in its charter)

Washington	**91-0626366**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
601 W. Main Ave., Suite 1017, Spokane, WA	**99201**
(Address of principal executive offices)	(Zip code)

(509) 232-7674
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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

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

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

Large accelerated filer ☐		Accelerated filer ☐
Non-accelerated filer ☐	(Do not check if a smaller reporting company)	Smaller reporting company ☑

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

At January 8, 2015 the registrant had 51,457,373 outstanding shares of $0.001 par value common stock.

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PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

DAYBREAK OIL AND GAS, INC.
Balance Sheets – Unaudited

	As of November 30, 2014	As of February 28, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 521,026	$ 500,431
Accounts receivable:		
Oil and natural gas sales	248,272	330,343
Joint interest participants	92,583	338,950
Other receivables, net	218,107	30,039
Production revenue receivable – current	120,000	120,000
Prepaid expenses and other current assets	189,493	29,397
Note receivable – current	2,162,222	793,727
Total current assets	3,551,703	2,142,887
OIL AND NATURAL GAS PROPERTIES, successful efforts method, net		
Proved properties	3,753,650	2,914,965
Unproved properties	1,282,356	1,261,156
PREPAID DRILLING COSTS	199,142	14,915
PRODUCTION REVENUE RECEIVABLE – NON-CURRENT	65,000	155,000
DEFFERED FINANCING COSTS, NET	1,165,033	1,326,600
NOTE RECEIVABLE – NON-CURRENT	3,306,068	2,756,273
OTHER ASSETS	106,178	106,114
Total assets	$ 13,429,130	$ 10,677,910
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable and other accrued liabilities	$ 1,458,905	$ 2,158,546
Accounts payable – related parties	852,266	952,652
Accrued interest	197,648	1,587
Notes payable, related party	250,100	250,100
12% Notes payable, net	341,572	327,871
12% Notes payable – related party, net	247,478	237,395
Current portion – debt, net	3,089,209	2,024,417
Line of credit	876,948	882,369
Total current liabilities	7,314,126	6,834,937
LONG TERM LIABILITIES:		
Long-term debt – net of current portion	10,874,559	6,629,638
Asset retirement obligation	26,175	22,079
Total liabilities	18,214,860	13,486,654
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' DEFICIT		
Preferred stock - 10,000,000 shares authorized, $0.001 par value;	-	-
Series A Convertible Preferred stock - 2,400,000 shares authorized, $0.001 par value, 6% cumulative dividends; 737,565 shares issued and outstanding	738	738
Common stock- 200,000,000 shares authorized; $0.001 par value, 51,448,373 and 55,509,411 shares issued and outstanding respectively	51,448	55,509
Additional paid-in capital	22,912,221	24,607,582
Accumulated deficit	(27,750,137)	(27,472,573)
Total stockholders' deficit	(4,785,730)	(2,808,744)
Total liabilities and stockholders' deficit	$ 13,429,130	$ 10,677,910

The accompanying notes are an integral part of these unaudited financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Operations – Unaudited

	For the Three Months Ended November 30		For the Nine Months Ended November 30	
	2014	**2013**	**2014**	**2013**
REVENUE:				
Oil and natural gas sales	$ 663,650	$ 425,035	$ 2,518,375	$ 1,131,847
OPERATING EXPENSES:				
Production expenses	86,140	44,697	251,625	160,652
Exploration and drilling	7,362	10,991	20,172	245,685
Depreciation, depletion, amortization, and impairment	134,873	56,922	426,366	261,641
Write down on asset disposal	-	39,254	-	39,254
General and administrative	230,040	347,722	849,964	943,594
Total operating expenses	458,415	499,586	1,548,127	1,650,826
OPERATING INCOME (LOSS)	205,235	(74,551)	970,248	(518,979)
OTHER INCOME (EXPENSE):				
Interest income	378,932	135,621	833,778	135,731
Interest expense	(718,586)	(472,166)	(2,081,590)	(946,296)
Total other income (expense)	(339,654)	(336,545)	(1,247,812)	(810,565)
NET LOSS	(134,419)	(411,096)	(277,564)	(1,329,544)
Cumulative convertible preferred stock dividend requirement	(33,097)	(38,113)	(100,020)	(118,165)
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (167,516)	$ (449,209)	$ (377,584)	$ (1,447,709)
NET LOSS PER COMMON SHARE				
Basic and diluted	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.03)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING				
Basic and diluted	51,448,373	55,072,884	55,035,219	50,967,879

The accompanying notes are an integral part of these unaudited financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows – Unaudited

	For the Nine Months Ended	
	November 30, 2014	November 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (277,564)	$ (1,329,544)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Stock compensation	2,515	10,546
Depreciation, depletion, and impairment expense	426,366	300,895
Amortization of debt discount	127,960	117,822
Amortization of deferred financing costs	316,126	133,020
Non-cash interest income	(64)	(158)
Changes in assets and liabilities:		
Accounts receivable - oil and gas sales	82,071	(61,579)
Accounts receivable - joint interest participants	246,367	(259,421)
Accounts receivable - other	(98,558)	31,638
Prepaid expenses and other current assets	(160,096)	(33)
Accounts payable and other accrued liabilities	(505,498)	(187,796)
Accounts payable - related parties	(100,386)	183,470
Accrued interest	195,406	(20,300)
Net cash provided by (used in) operating activities	254,645	(1,081,440)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and natural gas properties	(1,285,857)	(1,411,468)
Prepaid drilling costs	(184,227)	(175,906)
Deferred interest	655	(135,553)
Note receivable	(1,918,290)	(2,208,368)
Net cash used in investing activities	(3,387,719)	(3,931,295)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term debt	5,700,000	5,592,384
Proceeds from warrant exercise	7,000	-
Principal payments on long-term debt	(2,202,910)	(298,479)
Payment of deferred financing fees	(345,000)	(139,476)
Payments on line of credit	(5,421)	(27,000)
Net cash provided by financing activities	3,153,669	5,127,429
NET INCREASE IN CASH AND CASH EQUIVALENTS	20,595	114,694
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	500,431	79,996
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 521,026	$ 194,690
CASH PAID FOR:		
Interest	$ 1,465,881	$ 690,788
Income taxes	$ -	$ -

The accompanying notes are an integral part of these unaudited financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows – Unaudited (continued)

	For the Nine Months Ended			
	November 30, 2014		November 30, 2013	
SUPPLEMENTAL CASH FLOW INFORMATION:				
Unpaid additions to oil and natural gas properties	$	3,702	$	228,262
Conversion of warrants	$	1,874	$	-
Share-to-warrant exchange	$	428	$	-
Increase in note receivable for deferred interest	$	-	$	317,816
Increase in long-term note receivable with corresponding increase in long-term debt	$	-	$	362,816
Transfer agent balancing adjustment	$	140	$	-
Increase in note payable for stock acquisition and subsequent retirement	$	1,708,447	$	-
ARO asset and liability increase	$	2,428	$	27,079
Common stock and warrants issued for oil and natural gas properties	$	-	$	1,073,091
Common stock and warrants issued for deferred financing costs	$	-	$	852,236
Unpaid deferred financing fees	$	-	$	114,093
Repurchase of stock through payment of payroll taxes	$	490	$	758
Conversion of preferred stock to common stock	$	-	$	423

The accompanying notes are an integral part of these unaudited financial statements

NOTE 1 — ORGANIZATION AND BASIS OF PRESENTATION:

Organization

Originally incorporated as Daybreak Uranium, Inc., ("Daybreak Uranium") under the laws of the State of Washington on March 11, 1955, Daybreak Uranium was organized to explore for, acquire, and develop mineral properties in the Western United States. During 2005, management of the Company decided to enter the oil and natural gas exploration and production industry. On October 25, 2005, the Company shareholders approved a name change from Daybreak Mines, Inc. to Daybreak Oil and Gas, Inc. (referred to herein as "Daybreak" or the "Company") to better reflect the business of the Company.

All of the Company's oil and natural gas production is sold under contracts which are market-sensitive. Accordingly, the Company's financial condition, results of operations, and capital resources are highly dependent upon prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. These factors include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, the relative strength of the U.S. dollar, weather conditions, the price and availability of alternative fuels, and overall economic conditions, both foreign and domestic.

Basis of Presentation

The accompanying unaudited interim financial statements and notes for the Company have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q for quarterly reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"). Accordingly, they do not include all of the information and footnote disclosures normally required by accounting principles generally accepted in the United States of America for complete financial statements.

In the opinion of management, all adjustments considered necessary for a fair presentation of the financial statements have been included and such adjustments are of a normal recurring nature. Operating results for the nine months ended November 30, 2014 are not necessarily indicative of the results that may be expected for the fiscal year ending February 28, 2015.

These financial statements should be read in conjunction with the audited financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the fiscal year ended February 28, 2014.

Use of Estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make estimates and assumptions. These estimates and assumptions may affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. The accounting policies most affected by management's estimates and assumptions are as follows:

- The reliance on estimates of proved reserves to compute the provision for depreciation, depletion and amortization and to determine the amount of any impairment of proved properties;
- The valuation of unproved acreage and proved oil and gas properties to determine the amount of any impairment of oil and gas properties;
- Judgment regarding the productive status of in-progress exploratory wells to determine the amount of any provision for abandonment; and
- Estimates regarding abandonment obligations.

NOTE 2 — GOING CONCERN:

Financial Condition

The Company's financial statements for the nine months ended November 30, 2014 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. The Company has incurred net losses since entering the oil and natural gas exploration industry and as of November 30, 2014 has an accumulated deficit of $27,750,137 and a working capital deficit of $3,762,423 which raises substantial doubt about the Company's ability to continue as a going concern.

Management Plans to Continue as a Going Concern

The Company continues to implement plans to enhance its ability to continue as a going concern. Daybreak currently has an average 36.6% working interest and 28.4% net revenue interest in 20 producing wells in its East Slopes Project located in Kern County, California (the "East Slopes Project"). The revenue from these wells has created a steady and reliable source of revenue.

Additionally, the Company has become involved in a shallow oil play in an existing natural gas field in Lawrence County, Kentucky, through its acquisition of an average 25% working interest in approximately 7,300 acres in two large contiguous blocks in the Twin Bottoms Field in Lawrence County, Kentucky. The Company had 10 horizontal oil wells on production in Kentucky during portions of the nine months ended November 30, 2014 and has brought three additional horizontal oil wells onto production in December 2014. Daybreak's average working interest in these 13 oil wells is 22.4% and the average net revenue interest is 19.6% in these same wells.

The Company anticipates revenues will continue to increase as it participates in the drilling of more wells in California and Kentucky. Daybreak plans to continue its development drilling programs in both California and Kentucky at a rate that is compatible with its cash flow and funding opportunities.

The Company's sources of funds in the past have included the debt or equity markets and the sale of assets, while the Company has experienced revenue growth, which has resulted in positive cash flow from its oil and natural gas properties, it has not yet established a consistent positive cash flow on a company-wide basis. It will be necessary for the Company to obtain additional funding from the private or public debt or equity markets in the future. However, the Company cannot offer any assurance that it will be successful in executing the aforementioned plans to continue as a going concern.

Daybreak's financial statements as of November 30, 2014 do not include any adjustments that might result from the inability to implement or execute Daybreak's plans to improve our ability to continue as a going concern.

NOTE 3 — RECENT ACCOUNTING PRONOUNCEMENTS:

There are no new accounting pronouncements issued or effective that had or are expected to have, a material impact on the Company's financial statements.

NOTE 4 — CONCENTRATION OF CREDIT RISK:

Substantially all of the Company's trade accounts receivable result from crude oil and natural gas sales in California and Kentucky or joint interest billings to its working interest partners in California. This concentration of customers and joint interest owners may impact the Company's overall credit risk as these entities could be affected by similar changes in economic conditions as well as other related factors. Trade accounts receivable are generally not collateralized. There were no allowances for doubtful accounts for the Company's trade accounts receivable at November 30, 2014 and February 28, 2014, as all joint interest owners have a history of paying their obligations.

At the Company's East Slopes project in California, there is only one buyer available for the purchase of all oil production. At the Company's Twin Bottoms Field project located in Lawrence County, Kentucky, there is only one buyer available for the purchase of the oil production and only one buyer available for the purchase of the natural gas production. At November 30, 2014 and February 28, 2014 these three individual customers represented 100.0% of crude oil and natural gas revenues accounts receivable. If these buyers are unable to resell their products or if they lose a significant sales contract then the Company may incur difficulties in selling its oil and natural gas production.

The Company's oil and natural gas accounts receivable from California and Kentucky sales at November 30, 2014 and February 28, 2014 are set forth in the table below.

		At November 30, 2014		At February 28, 2014	
Project	Customer	Revenue Receivable	Percentage	Revenue Receivable	Percentage
California – East Slopes Project (Oil)	Plains Marketing	$ 152,568	61.4%	$ 244,384	74.0%
Kentucky – Twin Bottoms Field (Oil)	Appalachian Oil	83,793	33.8%	85,120	25.8%
Kentucky – Twin Bottoms Field (Natural Gas)	Jefferson Gas	11,911	4.8%	839	0.2%
		$ 248,272	100.0%	$ 330,343	100.0%

Other receivables balances primarily include amounts due from third parties that were involved in arranging financing transactions for the Company that have not yet been consummated and amounts advanced to certain minority working interest partners in Kentucky. Allowances for doubtful accounts in other receivables relate to amounts due from third parties for financing transactions. Other receivables balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Other receivables	$ 457,107	$ 269,039
Allowance for doubtful accounts	(239,000)	(239,000)
	$ 218,107	$ 30,039

NOTE 5 — PREPAID DRILLING COSTS:

During the nine months ended November 30, 2014 the Company was engaged in a multi-well drilling program at the Twin Bottoms Field in Lawrence County, Kentucky. The Company had made prepayments for drilling costs at November 30, 2014 and February 28, 2014 as set forth in the table below.

	November 30, 2014	February 28, 2014
California	$ 16,452	$ 16,452
Kentucky	182,690	(1,537)
	$ 199,142	$ 14,915

NOTE 6 — OIL AND GAS PROPERTIES:

Oil and gas property balances at November 30, 2014 and February 28, 2014 are set forth in the table below.

	November 30, 2014	February 28, 2014
Proved leasehold costs	$ 6,031	$ 2,236
Unproved leasehold costs	1,282,356	1,261,156
Costs of wells and development	976,740	492,970
Capitalized exploratory well costs	4,794,116	4,018,899
Total cost of oil and gas properties	7,059,243	5,775,261
Accumulated depletion, depreciation, amortization and impairment	(2,023,237)	(1,599,140)
Net oil and gas properties	$ 5,036,006	$ 4,176,121

NOTE 7 — PRODUCTION REVENUE RECEIVABLE:

Production revenue receivable balances of $185,000 in aggregate represent amounts due the Company from a portion of the sale price of a 25% working interest in East Slopes Project in Kern County, California that was acquired through the default of certain original working interest partners in the project. Production revenue receivable balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Production revenue receivable – current	$ 120,000	$ 120,000
Production revenue receivable – non-current	65,000	155,000
	$ 185,000	$ 275,000

NOTE 8 — DEFERRED FINANCING COSTS:

Deferred financing costs at November 30, 2014 and February 28, 2014 relate to the original and the amended credit facility with Maximilian Resources LLC, a Delaware limited liability company and successor by assignment to Maximilian Investors LLC (either party, as appropriate, is referred to in these notes to the financial statements as "Maximilian"), are set forth in the table below:

	November 30, 2014	February 28, 2014
Deferred financing costs – loan fees	$ 151,139	$ 151,139
Deferred financing costs – loan commissions	630,662	476,103
Deferred financing costs – fair value of warrants	530,488	530,488
Deferred financing costs – fair value of common stock	419,832	419,832
	1,732,121	1,577,562
Accumulated amortization	(567,088)	(250,962)
	$ 1,165,033	$ 1,326,600

Deferred financing costs of loan commissions increased $154,559 for the nine months ended November 30, 2014. The Company recognized amortization expense of $316,126 for the nine months ended November 30, 2014.

NOTE 9 — NOTE RECEIVABLE:

At November 30, 2014, the Company had advanced $8,312,500 in aggregate to App Energy, LLC, a Kentucky limited liability company ("App") through its credit facility. Note receivable balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Note receivable – current	$ 2,162,222	$ 793,727
Note receivable – non-current	3,306,068	2,756,273
	$ 5,468,290	$ 3,550,000

NOTE 10 — ACCOUNTS PAYABLE:

On March 1, 2009, the Company became the operator for its East Slopes Project. Additionally, the Company at that time assumed certain original partners' default liability of approximately $1.5 million representing a 25% working interest in the drilling and completion costs associated with the East Slopes Project four earning well program. The Company subsequently sold the same 25% working interest on June 11, 2009. Of the $1.5 million default, $255,349 remains unpaid and is included in the November 30, 2014 accounts payable balance.

NOTE 11 — ACCOUNTS PAYABLE- RELATED PARTIES:

The November 30, 2014 and February 28, 2014 accounts payable – related parties balances were comprised primarily of salaries of the Company's Executive Officers and certain employees; directors' fees; expense reimbursements; and interest to the Company's President and Chief Executive Officer on the 12% Subordinated Notes further described in Note 12 – Short-Term and Long-Term Borrowings below. Payment of these items has been deferred until the Company's cash flow situation improves.

NOTE 12 — SHORT-TERM AND LONG-TERM BORROWINGS:

Current Debt

Note Payable – Related Party

As of November 30, 2014 and February 28, 2014, the Company's President and Chief Executive Officer had loaned the Company $250,100 in aggregate that has been used for a variety of corporate purposes including an escrow requirement on a loan commitment; extension fees on third party loans; and a reduction of principal on the Company's credit line with UBS Bank. These loans are non-interest bearing loans and repayment will be made upon a mutually agreeable date in the future.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. At November 30, 2014, the Line of Credit had an outstanding balance of $876,948. Interest is payable monthly at a stated reference rate of 0.249% + 337.5 basis points and totaled $23,581 for the nine months ended November 30, 2014. The reference rate is based on the 30 day LIBOR ("London Interbank Offered Rate") and is subject to change from UBS.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a March 2010 private placement (of which $250,000 was from a related party) accrue interest at 12% per annum, payable semi-annually on January 29th and July 29th. The note principal is payable in full at the expiration of the term of the Notes, which is January 29, 2015. Should the Board of Directors, on the maturity date, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company's common stock at a conversion rate equal to 75% of the average closing price of the Company's common stock over the 20 consecutive trading days preceding December 31, 2014.

In conjunction with the Notes private placement, a total of 1,190,000 common stock purchase warrants were issued at a rate of two warrants for every dollar raised through the private placement. The warrants have an exercise price of $0.14 and expire on January 29, 2015. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $116,557 using the following weighted average assumptions: a risk free interest rate of 2.33%; volatility of 147.6%; and dividend yield of 0.0%. The fair value of the warrants was recognized as a discount to debt and is being amortized over the term of the Notes using the effective interest method. Amortization expense was $23,784 for the nine months ended November 30, 2014.

For the nine months ended November 30, 2014, one 12% Subordinated noteholder exercised the warrants associated with the 12% Note. A total of 50,000 warrants were exercised and resulted in 50,000 shares of Common Stock being issued to the noteholder.

Current Notes balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
12% Subordinated Notes	$ 345,000	$ 345,000
12% Subordinated Notes discount	(3,428)	(17,129)
	$ 341,572	$ 327,871

Current Notes, related party balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
12% Subordinated Notes, related party	$ 250,000	$ 250,000
12% Subordinated Notes discount, related party	(2,522)	(12,605)
	$ 247,478	$ 237,395

Non-current Debt

Maximilian Loan

On October 31, 2012, the Company entered into a loan agreement with Maximilian, which provided for a revolving credit facility of up to $20 million, maturing on October 31, 2016, with a minimum commitment of $2.5 million. The loan had annual interest of 18% and a monthly commitment fee of 0.5%. The Company also granted Maximilian a 10% working interest in its share of the oil and gas leases in Kern County, California. The relative fair value of this 10% working interest amounting to $515,638 was recognized as a debt discount and is being amortized over the original term of the loan. Amortization expense was $104,176 for the nine months ended November 30, 2014.

The Company also issued 2,435,517 warrants to third parties who assisted in the closing of the loan. The warrants have an exercise price of $0.044; contain a cashless exercise provision; have piggyback registration rights; and are exercisable for a period of five years expiring on October 31, 2017. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $98,084 and included the following assumptions: a risk free interest rate of 0.72%; stock price of $0.04, volatility of 153.44%; and a dividend yield of 0.0%. The fair value of the warrants was recognized as a financing cost and is being amortized as a part of deferred financing cost over the term of the loan. On March 10, 2014, one of the third parties exercised 2,118,900 warrants resulting in the issuance of 1,873,554 shares of the Company's common stock.

Maximilian Loan - Amended and Restated Loan Agreement

In connection with the Company's acquisition of a working interest from App in the Twin Bottoms Field in Lawrence County, Kentucky, the Company amended its loan agreement with Maximilian on August 28, 2013. The amended loan agreement provided for an increase in the revolving credit facility from $20 million to $90 million and a reduction in the annual interest rate from 18% to 12%. The monthly commitment fee of 0.5% per month on the outstanding principal balance remained unchanged. Advances under the amended loan agreement will mature on August 28, 2017. The obligations under the amended loan agreement continue to be secured by a perfected first priority security interest in substantially all of the personal property of the Company, and a mortgage on the Company's leases in Kern County, California. The amended loan agreement also provided for the revolving credit facility to be divided into two borrowing sublimits. The first borrowing sublimit is $50 million and is for borrowing by the Company, primarily for its ongoing oil and gas exploration and development activities. The second borrowing sublimit, of $40 million, is for loans to be extended by the Company, as lender, to App, as borrower pursuant to a Loan and Security Agreement entered into between the Company and App on August 28, 2013 (See Note 9 – Note Receivable).

The amended loan agreement contains customary covenants for loans of such type, including among other things, covenants that restrict the Company's ability to make capital expenditures, incur indebtedness, incur liens and dispose of property. The amended loan agreement also contains various events of default, including failure to pay principal and interest when due, breach of covenants, materially incorrect representations and bankruptcy or insolvency. If an event of default occurs, all of the Company's obligations under the amended loan agreement could be accelerated by Maximilian, causing all loans outstanding (including accrued interest and fees payable thereunder) to be declared immediately due and payable.

As consideration for Maximilian facilitating the Company's transactions with App and entering into the amended loan agreement, the Company (a) issued to Maximilian approximately 6.1 million common shares, representing 9.99% of the Company's outstanding common stock on a fully-diluted basis at the time of grant, and (b) issued approximately 6.1 million warrants to purchase shares of the Company's common stock representing the right to purchase up to an additional 9.99% of the Company's outstanding common stock on a fully-diluted basis, calculated as of the date of grant. The warrants have an exercise price of $0.10; contain a cash exercise provision and are exercisable for a period of three years expiring on August 28, 2016; and contain an exercise blocker provision that prevents any exercise of the warrants if such exercise and related issuance of common stock would increase the Maximilian holdings of the Company's common stock to more than 9.99% of the Company's currently issued and outstanding shares at the time of the exercise. The Company also granted to Maximilian a 50% net profits interest in the Company's 25% working interest, after the Company recovers its investment, in the Company's working interest in its Kentucky acreage, pursuant to an Assignment of Net Profits Interest entered into as of August 28, 2013 by and between the Company and Maximilian.

On May 28, 2014, at Maximilian's request, the Company finalized a share-for-warrant exchange agreement in which Maximilian returned to the Company 427,729 common shares and was in turn issued the same number of warrants containing the same provisions as the originally issued warrants. This share-for-warrant exchange occurred so that Maximilian would hold no more than 9.99% of the Company's common shares, issued and outstanding. The Company determined that the share-for-warrant exchange did not result in any incremental fair value.

On August 21, 2014, the Company entered into a First Amendment to Amended and Restated Loan and Security Agreement and Share Repurchase Agreement (the "Amendment") with Maximilian under its Amended and Restated Loan and Security Agreement dated as of August 28, 2013. The Amendment secured for the Company an additional advance of $2,200,000 under its credit facility with Maximilian since the advances made by Maximilian had already exceeded its minimum funding commitment. Additionally, Maximilian agreed to temporarily reduce the required monthly payment made by the Company until it has paid $1,000,000 less than principal payments required by the previous agreement. As of November 30, 2014, the Company had recognized $700,000 of the reduced monthly principal payments program. Furthermore, Maximilian agreed to reduce the regular interest rate applicable to the loan from 12% per annum to 9% per annum and the default interest rate by 3%.

The additional advance, the reduction in the required monthly payment and the reduction in the interest rate were facilitated through the Company's acquisition of 5,694,823 shares of its common stock held by Maximilian. The repurchased shares were cancelled and restored to the status of authorized, but unissued stock. The Company paid for the share repurchase transaction through an advance of $1,708,447 under the existing loan agreement with Maximilian.

During the nine months ended November 30, 2014, the Company received multiple advances from Maximilian of approximately $7.4 million in aggregate that were used to participate in the multi-well drilling program at the Twin Bottoms Field in Kentucky; to advance funds to App through a long-term note receivable; and, to fund the acquisition referenced in the prior paragraph of the Company's common stock from Maximilian. The Company made principal payments of approximately $2.2 million to Maximilian during the nine months ended November 30, 2014. The Company has recognized $154,559 during the nine months ended November 30, 2014 in deferred financing costs associated with these advances which are being amortized over the amended term of the revolving credit facility.

Current debt balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Maximilian note	$ 3,224,918	$ 2,163,405
Maximilian note - discount	(135,709)	(138,988)
	$ 3,089,209	$ 2,024,417

Non-current debt balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Maximilian note	$ 10,977,727	$ 6,833,703
Maximilian note - discount	(103,168)	(204,065)
	$ 10,874,559	$ 6,629,638

NOTE 13 — STOCKHOLDERS' DEFICIT:

Series A Convertible Preferred Stock

The Company has designated 2,400,000 shares of the 10,000,000 preferred shares as Series A Convertible Preferred Stock ("Series A Preferred"), with a $0.001 par value. At November 30, 2014, there were 737,565 shares issued and outstanding, that had not been converted into our common stock. As of November 30, 2014, there are 41 accredited investors who have converted 662,200 Series A Preferred shares into 1,986,600 shares of Daybreak common stock. The conversions of Series A Preferred that have occurred since the Series A Preferred was first issued in July 2006 is set forth in the table below.

Fiscal Period	Shares of Series A Preferred Converted to Common Stock	Shares of Common Stock Issued from Conversion	Number of Accredited Investors
Year Ended February 29, 2008	102,300	306,900	10
Year Ended February 28, 2009	237,000	711,000	12
Year Ended February 28, 2010	51,900	155,700	4
Year Ended February 28, 2011	102,000	306,000	4
Year Ended February 29, 2012	-	-	-
Year Ended February 28, 2013	18,000	54,000	2
Year Ended February 28, 2014	151,000	453,000	9
Nine Months Ended November 30, 2014	-	-	-
Totals	**662,200**	**1,986,600**	**41**

Holders of Series A Preferred shall be paid dividends, in the amount of 6% of the original purchase price per annum. Dividends are cumulative from the date of the final closing of the private placement, whether or not in any dividend period or periods we have assets legally available for the payment of such dividends. Dividends earned since issuance for each fiscal year and the nine months ended November 30, 2014 are set forth in the table below:

Fiscal Period	Shareholders at Period End	Earned Dividends
Year Ended February 28, 2007	100	$ 155,311
Year Ended February 29, 2008	90	242,126
Year Ended February 28, 2009	78	209,973
Year Ended February 28, 2010	74	189,973
Year Ended February 28, 2011	70	173,707
Year Ended February 29, 2012	70	163,624
Year Ended February 28, 2013	68	161,906
Year Ended February 28, 2014	59	151,323
Nine Months Ended November 30, 2014	59	100,020
Total Accumulated Dividends		**$ 1,547,963**

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value common stock of which 51,448,373 shares were issued and outstanding as of November 30, 2014. In comparison, at February 28, 2014, a total of 55,509,411 shares were issued and outstanding. The decrease of 4,061,038 shares was attributable as shown below:

	Common Stock Balance	Par Value
Common stock, Issued and Outstanding, February 28, 2014	55,509,411	
Exercise of warrants issued with 12% Subordinated Notes	50,000	$ 50
Exercise of warrants issued in connection with financing	1,873,554	$ 1,874
Common stock-for-warrant exchange (Maximilian)	(427,729)	$ (428)
Transfer agent balancing adjustment	140,000	$ 140
Repurchase of common stock through financing	(5,694,823)	$ (5,695)
Common stock returned to 2009 Stock Plan for payroll taxes	(2,040)	$ 2
Common stock, Issued and Outstanding, November 30, 2014	51,448,373	

NOTE 14 — WARRANTS:

Warrants outstanding and exercisable as of November 30, 2014 are set forth in the table below:

	Warrants	Exercise Price	Remaining Life (Years)	Exercisable Warrants Remaining
12% Subordinated notes	1,190,000	$0.14	0.16	1,040,000
Warrants issued in 2010 for services	150,000	$0.14	0.38	150,000
Warrants issued in 2012 for debt financing	2,435,517	$0.044	3.00	316,617
Warrants issued for Kentucky oil project	3,498,601	$0.10	1.75	3,498,601
Warrants issued for Kentucky debt financing	2,623,951	$0.10	1.75	2,623,951
Warrants issued for Kentucky debt financing	309,503	$0.214	3.75	309,503
Warrants issued in share-for-warrant exchange	427,729	$0.10	1.75	427,729
	10,635,301			8,366,401

There were no warrants that expired during the nine months ended November 30, 2014. During the nine months ended November 30, 2014, there were 50,000 warrants exercised for a total of $7,000 that had been issued in conjunction with the 12% subordinated Notes and 2,118,900 warrants exercised that were issued in conjunction with financing the Company received in 2012 for a total of 2,168,900 warrants that were exercised in aggregate. There were 427,729 warrants issued during the nine months ended November 30, 2014 in connection with the Maximilian share-for-warrants exchange. The remaining outstanding warrants as of November 30, 2014, have a weighted average exercise price of $0.11, a weighted average remaining life of 1.7 years, and an intrinsic value of $292,406.

NOTE 15 — RESTRICTED STOCK AND RESTRICTED STOCK UNIT PLAN:

At November 30, 2014, a total of 3,000,000 shares were awarded and are fully vested, with 2,986,220 shares of restricted stock that remain outstanding and are fully vested under the 2009 Restricted Stock and Restricted Stock Unit Plan (the "2009 Plan"). A total of 1,013,780 common stock shares remained available at November 30, 2014 for issuance pursuant to the 2009 Plan. A summary of the 2009 Plan issuances is set forth in the table below:

Grant Date	Shares Awarded	Vesting Period	Shares Vested[(1)]	Shares Returned[(2)]	Shares Outstanding (Unvested)
4/7/2009	1,900,000	3 Years	1,900,000	-	-
7/16/2009	25,000	3 Years	25,000	-	-
7/16/2009	625,000	4 Years	619,130	5,870	-
7/22/2010	25,000	3 Years	25,000	-	-
7/22/2010	425,000	4 Years	417,090	7,910	-
	3,000,000		2,986,220[(1)]	13,780[(2)]	-

(1) Does not include shares that were withheld to satisfy such tax liability upon vesting of a restricted award by a Plan Participant, and subsequently returned to the 2009 Plan.

(2) Reflects the number of common shares that were withheld pursuant to the settlement of the number of shares with a fair market value equal to such tax withholding liability, to satisfy such tax liability upon vesting of a restricted award by a Plan Participant.

For the nine months ended November 30, 2014, the Company recognized compensation expense related to the above restricted stock grants in the amount of $2,515. For the nine months ended November 30, 2014, there were 2,040 shares of the Company's common stock relating to the 2009 Plan that were returned to the 2009 Plan to satisfy an employee's payroll tax liability upon the vesting of the shares.

NOTE 16 — INCOME TAXES:

Reconciliation between actual tax expense (benefit) and income taxes computed by applying the U.S. federal income tax rate and state income tax rates to income from continuing operations before income taxes is set forth in the table below:

	November 30, 2014	February 28, 2014
Computed at U.S. and state statutory rates (40%)	$ (111,024)	$ (559,340)
Permanent differences	108,489	94,980
Changes in valuation allowance	2,535	464,360
	$ -	$ -

Tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred liabilities are set forth in the table below:

	November 30, 2014	February 28, 2014
Deferred tax assets:		
Net operating loss carryforwards	$ 8,752,681	$ 8,344,222
Oil and gas properties	(1,151,823)	(832,267)
Stock based compensation	88,471	87,716
Other	(98,565)	(11,442)
Less valuation allowance	(7,590,764)	(7,588,229)
	$ -	$ -

At November 30, 2014, Daybreak had estimated net operating loss ("NOL") carryforwards for federal and state income tax purposes of approximately $21,881,703 which will begin to expire, if unused, beginning in 2024. The valuation allowance increased approximately $2,535 for the nine months ended November 30, 2014 and increased by $464,360 for the year ended February 28, 2014. Section 382 of the Internal Revenue Code places annual limitations on the Company's NOL carryforward.

The above estimates are based on management's decisions concerning elections which could change the relationship between net income and taxable income. Management decisions are made annually and could cause estimates to vary significantly.

NOTE 17 — COMMITMENTS AND CONTINGENCIES:

Various lawsuits, claims and other contingencies arise in the ordinary course of the Company's business activities. While the ultimate outcome of any future contingency is not determinable at this time, management believes that any liability or loss resulting therefrom will not materially affect the financial position, results of operations or cash flows of the Company.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage that is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company is not aware of any environmental claims existing as of November 30, 2014. There can be no assurance, however, that current regulatory requirements will not change or that past non-compliance with environmental issues will not be discovered on the Company's oil and gas properties.

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

The following discussion is management's assessment of the current and historical financial and operating results of the Company and of our financial condition. It is intended to provide information relevant to an understanding of our financial condition, changes in our financial condition and our results of operations and cash flows and should be read in conjunction with our unaudited financial statements and notes thereto included elsewhere in this Quarterly Report on Form 10-Q for the nine months ended November 30, 2014 and in our Annual Report on Form 10-K for the year ended February 28, 2014. References to "Daybreak", the "Company", "we", "us" or "our" mean Daybreak Oil and Gas, Inc.

Cautionary Statement Regarding Forward-Looking Statements

Certain statements contained in our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") are intended to be covered by the safe harbor provided for under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act.

All statements other than statements of historical fact contained in this MD&A report are inherently uncertain and are forward-looking statements. Statements that relate to results or developments that we anticipate will or may occur in the future are not statements of historical fact. Words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will" and similar expressions identify forward-looking statements. Examples of forward-looking statements include, without limitation, statements about the following:

- Our future operating results;
- Our future capital expenditures;
- Our future financing;
- Our expansion and growth of operations; and
- Our future investments in and acquisitions of oil and natural gas properties.

We have based these forward-looking statements on assumptions and analyses made in light of our experience and our perception of historical trends, current conditions, and expected future developments. However, you should be aware that these forward-looking statements are only our predictions and we cannot guarantee any such outcomes. Future events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- General economic and business conditions;
- Exposure to market risks in our financial instruments;
- Fluctuations in worldwide prices and demand for oil and natural gas;
- Our ability to find, acquire and develop oil and gas properties;
- Fluctuations in the levels of our oil and natural gas exploration and development activities;
- Risks associated with oil and natural gas exploration and development activities;
- Competition for raw materials and customers in the oil and natural gas industry;
- Technological changes and developments in the oil and natural gas industry;
- Legislative and regulatory uncertainties, including proposed changes to federal tax law and climate change legislation, regulation of hydraulic fracturing and potential environmental liabilities;
- Our ability to continue as a going concern;
- Our ability to secure financing under any commitments as well as additional capital to fund operations; and
- Other factors discussed elsewhere in our Form 10-K for the year ended February 28, 2014; in this Form 10-Q; in our other public filings, press releases; and, discussions with Company management.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in our Form 10-K for the year ended February 28, 2014 and in this Form 10-Q occur, or should any underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically undertake no obligation to publicly update or revise any information contained in any forward-looking statement or any forward-looking statement in its entirety, whether as a result of new information, future events, or otherwise, except as required by law.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

Introduction and Overview

We are an independent oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing oil and natural gas reserves through exploration and development activities, and selling the production from those reserves at a profit. To be successful, we must, over time, be able to find oil and natural gas reserves and then sell the resulting production at a price that is sufficient to cover our finding costs, operating expenses, administrative costs and interest expense, plus offer us a return on our capital investment. A secondary means of generating returns can include the sale of either producing or non-producing lease properties.

Our longer-term success depends on, among many other factors, the acquisition and drilling of commercial grade oil and natural gas properties and on the prevailing sales prices for oil and natural gas along with associated operating expenses. The volatile nature of the energy markets makes it difficult to estimate future prices of oil and natural gas; however, any prolonged period of depressed prices would have a material adverse effect on our results of operations and financial condition.

Our operations are focused on identifying and evaluating prospective oil and natural gas properties and funding projects that we believe have the potential to produce oil or natural gas in commercial quantities. We conduct all of our drilling, exploration and production activities in the United States, and all of our revenues are derived from sales to customers within the United States. Currently, we are in the process of developing two multi-well oilfield projects; one in Kern County, California and the other in Lawrence County, Kentucky.

Our management cannot provide any assurances that Daybreak will continue to sustain profitability. As a small company, we are more susceptible to the numerous business, investment and industry risks that have been described in Item 1A. Risk Factors of our Annual Report on Form 10-K for the fiscal year ended February 28, 2014 and in Part III, Item 1A. Risk Factors of this 10-Q Report. Throughout this Quarterly Report on Form 10-Q, oil is shown in barrels ("Bbls"); natural gas is shown in thousands of cubic feet ("Mcf") or British Thermal Units ("BTU") unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent ("BOE").

Year-to-Date Results

During the current fiscal year, we have been successful in accomplishing the following objectives:

- *Continuing our drilling program in Kentucky* – We have brought eight additional horizontal oil wells onto production through December 2014.
- *Improving our cash flow* – Oil and natural gas revenue has increased by approximately $1.4 million or 122.5% in comparison to the nine months ended November 30, 2013, while the average realized hydrocarbon price on a BOE basis has declined 9.2% from $95.56 to $86.78 during the nine months ended November 30, 2014.
- *Reducing our net loss* – Our net loss for the nine months ended November 30, 2014 was $277,564 in comparison to $1,329,544 for the nine months ended November 30, 2013. This decrease in the net loss represents a 79.1% decrease that was achieved through increasing our revenues from our increased oil production and decreasing our expenses.

Below is summary of our oil and natural gas projects in California and Kentucky.

Kern County, California (East Slopes Project)

The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Drilling targets are porous and permeable sandstone reservoirs which exist at depths of 1,200 feet to 4,500 feet. Since January 2009, we have participated in the drilling of 25 wells in this project. During the nine months ended November 30, 2014, we had production from 20 wells. We have been the Operator at the East Slopes Project since March 2009.

We currently have production from five reservoirs at our Sunday, Bear, Black, Ball and Dyer Creek locations. The Sunday property has six producing wells, while the Bear property has nine producing wells. The Black property is the smallest of all currently producing reservoirs, and currently has two producing wells at this property. The Ball property also has two producing wells while the Dyer Creek property has one producing well. There are several other similar prospects on trend with the Bear, Black and Dyer Creek reservoirs exhibiting the same seismic characteristics. Some of these prospects, if successful, would utilize the Company's existing production facilities. In addition to the current field development, there are several other exploratory prospects that have been identified from the seismic data, which we plan to drill in the future.

Producing Properties

Sunday Property

In November 2008, we made our initial oil discovery drilling the Sunday #1 well. The well was put on production in January 2009. Production is from the Vedder sand at approximately 2,000 feet. During 2009, we drilled three development wells including one horizontal well. We have a 37.5% working interest with a 26.1% net revenue interest ("NRI") in the Sunday #1 well. For both the Sunday #2 and Sunday #3 wells, we have a 33.8% working interest with a 24.3% NRI. We also have a 33.8% working interest with a 27.1% NRI in the Sunday #4H well. During May and June 2013, we drilled two additional development wells; the Sunday #5 and Sunday #6 on this property. We have a 37.5% working interest and a NRI of 30.1% in both of these new wells. Our average working interest and NRI for the Sunday property in aggregate is 35.6% and 27.0%, respectively. The Sunday reservoir is estimated to be approximately 35 acres in size with the potential for at least five more development wells to be drilled in the future.

Bear Property

In February 2009, we made our second oil discovery drilling the Bear #1 well, which is approximately one mile northwest of our Sunday discovery. The well was put on production in May 2009. Production is from the Vedder sand at approximately 2,200 feet. In December 2009, we began a development program on this property by drilling and completing the Bear #2 well. In April 2010, we successfully drilled and completed the Bear #3 and the Bear #4 wells. In May and June 2013, we drilled three additional development wells; the Bear #5, Bear #6 and Bear #7 on this property. In November 2013, we drilled and put on production two additional development wells; the Bear #8 and Bear #9. We have a 37.5% working interest in all wells at the Bear Property. Our NRI in the Bear #1, Bear #2, Bear #3 and Bear #4 wells is 26.1%. For the Bear #5, Bear #6 and Bear #7 wells our NRI is 30.1%. Our NRI in the Bear #8 and Bear #9 wells is 31.7%. The average working interest and NRI for the Bear property in aggregate is 37.5% and 28.7%, respectively. The Bear reservoir is estimated to be approximately 62 acres in size with the potential for at least ten more development wells to be drilled in the future.

Black Property

The Black property was acquired through a farm-in arrangement with a local operator. The Black property is just south of the Bear property and is on the same fault system. The Black #1 well was completed and put on production in January 2010. In May 2013, we drilled a development well, the Black #2 on this property. Production for both of these wells is from the Vedder sand at approximately 2,200 feet. We have a 37.5% working interest with a 29.8% NRI in all wells on this property. The Black reservoir is estimated to be approximately 13 acres in size with the potential for at least three more development wells to be drilled in the future.

Ball Property

The Ball #1-11 well was drilled and put on production in late October 2010. In June 2013, we drilled a development well the Ball #2-11, on this property. Production on this property is from the Vedder sand at approximately 2,500 feet. We have a 37.5% working interest with a 31.2% NRI in all wells on this property. Our 3-D seismic data indicates a reservoir approximately 38 acres in size with the potential for at least three more development wells to be drilled in the future.

Dyer Creek Property

The Dyer Creek #67X-11 ("DC67X") well was also drilled and put on production in late October 2010. This well also produces from the Vedder sand and is located to the north of the Bear property on the same trapping fault. We have a 37.5% working interest with a 31.2% NRI in all wells on this property. The Dyer Creek property has the potential for at least three more development wells to be drilled in the future.

Sunday Central Processing and Storage Facility

The oil produced from our acreage in California is considered heavy oil. The oil ranges from 14° to 16° API (American Petroleum Institute) gravity. All of the oil from our five producing properties is processed, stored and sold from the Sunday central processing and storage facility. The oil must be heated to separate and remove water to prepare it to be sold. We constructed these facilities during the summer and fall of 2009 and at the same time established electrical service for our field by constructing three miles of power lines. We have completed an upgrade program to this facility including the addition of a second oil storage tank to handle the additional oil production from the wells drilled in 2013.

By utilizing the Sunday centralized production facility our average operating costs have been reduced from over $40 per barrel in 2009 to a monthly average of approximately $12 per barrel of oil for the nine months ended November 30, 2014. With this centralized facility and having permanent electrical power available, we are ensuring that our operating expenses are kept to a minimum.

Exploration Properties

Bull Run Prospect

This prospect is located in the southern portion of our acreage position. The drilling targets are the Etchegoin and Santa Margarita sands located between 800 and 1,200 feet deep. Utilizing the data received from a previously drilled well that was not commercially successful, we expect to drill another exploratory well on this prospect during 2015. Future Bull Run wells will require a pilot steam flood and additional production facilities. We estimate that the Bull Run prospect is 70 acres in size. We have a 37.5% working interest in this prospect. A drilling permit has been received and drilling is expected to occur during calendar year 2015.

Glide-Kendall Prospect

This prospect is located in the southern portion of our acreage position. The drilling targets are the Olcese and Eocene sands between 1,000 and 2,000 feet deep. We estimate that the Glide Kendall prospect is 200 acres in size. We have a 37.5% working interest in this prospect.

Sherman Prospect

This prospect is also located in the southern portion of our acreage position. The drilling targets are the Olcese and Etchegoin sands between 1,000 and 2,000 feet deep. We estimate that the Sherman Prospect is 100 acres in size. We have a 37.5% working interest in this prospect.

Tobias Prospect

This prospect is also located in the central portion of our acreage position. The drilling targets are the Vedder and Eocene sands between 2,000 and 4,500 feet deep. We estimate that the Tobias prospect is 60 acres in size. We have a 37.5% working interest in this prospect.

California Drilling Plans

Future drilling plans include a combination of both exploratory drilling and development well drilling. Planned drilling activity will be undertaken as soon as possible after all applicable regulatory permits are received; financing is in place; and, there is an improvement in oil prices.

Lawrence County, Kentucky (Twin Bottoms Field)

The Twin Bottoms Field, comprising approximately 7,300 acres in two large contiguous blocks, is located in the Appalachian Basin of eastern Kentucky. Log data from existing vertical gas wells in the field indicate the existence of proved oil reserves in the Berea Oil Sand, located at approximately 2,000 feet. The lateral leg of each well will be between 2,000 feet and 4,500 feet in length. We have an average 25% working interest and an average NRI of 21.9% in most horizontal wells in this project. The oil produced from our acreage in Kentucky is light crude oil measuring between 42° and 44° API gravity. We are not the Operator of the Twin Bottoms Field project, but we rely on the experience of the current Operator and their knowledge of this Field.

As of November 30, 2014, we had 10 producing horizontal oil wells in the Twin Bottoms Field. Our first well, the Grove H-1 was put on production in October 2013. Our second well, the Grove H-3 was put on production in December 2013. The Grove H-4 and Grove H-5, our third and fourth wells, were put on production in February 2014. The Dillon H-6 well was put on production in March 2014. The next four horizontal oil wells, the Grove H-7, Grove H-8, Grove H-9 and Grove H-10 were put on production in June and July 2014. The Jackson H-20 well was temporarily produced in November 2014 to relieve pressure on the wellbore. It subsequently was placed on permanent production in January 2015. In December 2014, three additional wells, the Lyons H-23, Lyons H-24 and the Dillon H-22 were all put on production.

Kentucky Drilling Plans

Future drilling activity will be undertaken as soon as possible after all applicable regulatory permits are received; financing is in place; and, there is an improvement in oil prices.

Encumbrances

The Company's debt obligations, pursuant to a loan agreement entered into by and between Maximilian Resources LLC, a Delaware limited liability company and successor by assignment to Maximilian Investors LLC (either party, as appropriate, is referred to in this MD&A as "Maximilian"), as lender, and the Company are secured by a perfected first priority security interest in substantially all of the personal property of the Company, and a mortgage on our leases in Kern County, California encompassing the Sunday, Bear, Black, Ball and Dyer Creek properties. For further information on the loan agreement refer to the discussion under the caption "Long-Term Borrowings" in this MD&A.

Results of Operations – Three Months Ended November 30, 2014 compared to the Three Months Ended November 30, 2013

Revenues. Our revenues are derived entirely from the sale of our share of oil and natural gas production. The price we receive for oil sales in both California and Kentucky is based on prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") Cushing, Oklahoma delivery contracts, less deductions that vary by grade of crude oil sold and transportation costs. The price we receive for natural gas sales in Kentucky per Mcf is based on the Columbia Gas Transmission Corp. Appalachia Index ("TCO Appalachia") whereby we will receive 76% of the TCO Appalachia price per dekatherm (DTH) less $0.25 compression cost for each Mcf of gas delivered. We do not have any natural gas revenues in California.

California Oil Sales

For the three months ended November 30, 2014, the average WTI price was $80.72 and our average realized sale price was $75.80, representing a discount of $4.92 per barrel or 6.1% lower than the average WTI price. In comparison, for the three months ended November 30, 2013, the average WTI prices was $100.23 and our average realized sale price was $93.57 representing a discount of $6.66 per barrel or 6.6% lower than the average WTI price. Historically, the sale price we receive for California heavy oil has been less than the quoted WTI price because of the lower API gravity of our California oil in comparison to WTI oil API gravity.

Kentucky Oil Sales

Our first oil sales in Kentucky occurred in October 2013. For the three months ended November 30, 2014, our average realized sale price was $84.11 in comparison to the average WTI price of $80.72 representing a premium of $3.39 per barrel or 4.2% higher than the average WTI price. In comparison, for the three months ended November 30, 2013 the average WTI price was $100.23 and our average realized sale price was $94.65 representing a discount of $5.58 per barrel or 5.6% lower than the average WTI price. We are unable to forecast how long we will continue to receive a premium for our Kentucky oil sales in comparison to the WTI price as there are many factors beyond our control that dictate the price we receive on our oil sales.

Kentucky Natural Gas Sales

Our first natural gas sales in Kentucky also occurred in October 2013. For the three months ended November 30, 2014, our average realized sale price was $3.15 per Mcf in comparison to the average Henry Hub price of $3.94 per million BTU representing a discount of $0.79 per Mcf or 20.1% lower than the average Henry Hub price. In comparison, for the three months ended November 30, 2013 the average realized sale price was $2.13 per Mcf in comparison to the average Henry Hub price of $3.65 per million BTU representing a discount of $1.52 or 41.6% lower than the average Henry Hub price.

Our oil and natural gas revenues for the three months ended November 30, 2014 and 2013 are set forth in the table below:

	Three Months Ended November 30, 2014		Three Months Ended November 30, 2013	
Project	**Sales Revenue**	**Percentage**	**Sales Revenue**	**Percentage**
California – East Slopes Project (Oil)	$ 308,688	46.5%	$ 339,800	79.9%
Kentucky – Twin Bottoms Field (Oil)	334,156	50.4%	83,600	19.7%
Kentucky – Twin Bottoms Field (Natural gas)	20,806	3.1%	1,635	0.4%
	$ 663,650	100.0%	$ 425,035	100.0%

Revenues for the three months ended November 30, 2014 increased $238,615 or 56.1% to $663,650 in comparison to revenues of $425,035 for the three months ended November 30, 2013. In California, oil revenues decreased $31,112 or 9.2% due to a 19.0% decrease in the average realized sales price. In Kentucky, oil revenues increased $250,556 or 299.7% to $334,156 due to a 333.60% increase in the sales volume since 10 wells were on production in comparison to one well on production for the three months ended November 30, 2013. Natural gas sales revenues increased $19,171 also due to 10 wells being on production in comparison to one well on production for the three months ended November 30, 2013. The average realized sales price of all hydrocarbon sales in California and Kentucky on a BOE basis for the three months ended November 30, 2014 was $72.57 in comparison to $91.54 for the three months ended November 30, 2013.

Production for the three months ended November 30, 2014 was from 30 wells in aggregate; 20 wells in California and 10 wells in Kentucky. In California, our net production volume for the three months ended November 30, 2014 was 4,072 barrels of oil in comparison to 3,632 barrels for the three months ended November 30, 2013. In Kentucky, production for the three months ended November 30, 2014 was 5,072 BOE from 10 wells in comparison to 1,047 BOE from one well for the three months ended November 30, 2013. Average daily production was 100 BOE in aggregate; 45 BOE per day in California and 55 BOE per day in Kentucky.

Operating Expenses. Total operating expenses including non-cash DD&A for the three months ended November 30, 2014 decreased by $41,171 or 8.2% to $458,415 in comparison to $499,586 for the three months ended November 30, 2013. On a BOE basis, total operating expenses for the three months ended November 30, 2014 decreased $56.66 per barrel or 47.0% to $50.13 per barrel in comparison to $106.79 per barrel for the three months ended November 30, 2013.

Operating expenses for the three months ended November 30, 2014 and November 30, 2013 are set forth in the table below:

	Three Months Ended November 30, 2014		Three Months Ended November 30, 2013	
	Expenses	**Percentage**	**Expenses**	**Percentage**
Production expenses	$ 86,140	18.8%	$ 44,697	8.9%
Exploration and drilling expenses	7,362	1.6%	10,991	2.2%
Depreciation, Depletion, Amortization, and Impairment (“DD&A”)	134,873	29.4%	56,922	11.4%
Write down on asset disposal	-	-	39,254	7.9%
General and Administrative (“G&A”) expenses	230,040	50.2%	347,722	69.6%
Total operating expenses	$ 458,415	100.0%	$ 499,586	100.0%

Production expenses include expenses associated with the generation of oil and gas revenues, road maintenance, control of well insurance, property taxes and well workover expenses; and, relate directly to the number of wells that are in production. For the three months ended November 30, 2014, these expenses increased by $41,443 or 92.7% to $86,140 in comparison to $44,697 for the three months ended November 30, 2013. For the three months ended November 30, 2014 we had 20 wells on production in California and 10 wells on production in Kentucky in comparison to 20 wells in California and one well in Kentucky for the three months ended November 30, 2013. On a BOE basis production expenses in California were $13.04 per barrel for the three months ended November 30, 2014 in comparison to $12.19 per barrel for the three months ended November 30, 2013. In Kentucky, on a BOE basis, production expenses were $6.51 per barrel for the three months ended November 30, 2014 in comparison to $4.52 per barrel for the three months ended November 30, 2013. Combined LOE for both California and Kentucky on a BOE basis was $9.42 per barrel for the three months ended November 30, 2014 in comparison to $10.47 per barrel for the three months ended November 30, 2013. Production expenses represented 18.8% of total operating expenses for the three months ended November 30, 2014.

Production expenses in California and Kentucky for the three months ended November 30, 2014 and November 30, 2013 are set forth in the table below:

	Three Months Ended November 30, 2014		Three Months Ended November 30, 2013	
	Expenses	**Percentage**	**Expenses**	**Percentage**
California – East Slopes Project	$ 53,119	61.7%	$ 43,890	98.2%
Kentucky – Twin Bottoms Field	33,021	38.3%	807	1.8%
Total production expenses	$ 86,140	100.0%	$ 44,697	100.0%

Exploration and drilling expenses include geological and geophysical ("G&G") expenses as well as leasehold maintenance and dry hole expenses. These expenses decreased $3,629 or 33.0% to $7,362 for the three months ended November 30, 2014 in comparison to $10,991 the three months ended November 30, 2013. Exploration and drilling expenses represented 1.6% of total operating expenses.

DD&A expenses relate to equipment, proven reserves and property costs, along with impairment and is another component of operating expenses. For the three months ended November 30, 2014, DD&A expenses increased $77,951 or 136.9% to $134,873 in comparison to $56,922 for the three months ended November 30, 2013. The increase in DD&A is directly related to our involvement in the Twin Bottoms Field in Kentucky and the depletion of those associated reserves where 10 wells were on production for the three months ended November 30, 2014 in comparison to one well on production for the three months ended November 30, 2013. On a BOE basis, DD&A and impairment represented $14.75 and $12.17 per barrel for the three months ended November 30, 2014 and 2103, respectively. DD&A expenses represented 29.4% of total operating expenses.

G&A expenses include the salaries of six full-time employees, including management. Other items included in our G&A expenses are legal and accounting expenses, director fees, stock compensation, investor relations fees, travel expenses, insurance, Sarbanes-Oxley ("SOX") compliance expenses and other administrative expenses necessary for an operator of oil and gas properties as well as for running a public company. For the three months ended November 30, 2014, G&A expenses decreased $117,682 or 33.8% to $230,040 in comparison to $347,722 for the three months ended November 30, 2013. Legal, accounting and reserve reporting expenses decreased by $52,700 for the three months ended November 30, 2014. Travel expenses decreased $34,700 because of the decrease in drilling activity during the three months ended November 30, 2014 in comparison to the three months ended November 30, 2013. Additionally, director fees decreased $12,500 due to fewer individuals on the Board of Directors of the Company. Press release expenses also decreased by approximately $7,300. For the three months ended November 30, 2014, we received, as Operator in California, administrative overhead reimbursement of $16,176 for the East Slopes Project which was used to directly offset certain employee salaries. We are continuing a program of reducing all of our G&A costs wherever possible. G&A expenses represented 50.2% of total operating expenses for the three months ended November 30, 2014.

Interest income for the three months ended November 30, 2014 increased $243,311 in comparison to the three months ended November 30, 2013 primarily due to interest income earned on the Note receivable from App Energy. For further discussion on this Note refer to the App Loan Agreement under Long-term Financing section in this MD&A.

Interest expense for the three months ended November 30, 2014 increased $246,420 in comparison to the three months ended November 30, 2013. The increase in interest expense was primarily from higher loan balances on our credit facility due to drilling program and lending activities in Kentucky, and the acquisition of our common stock shares from Maximilian. The credit facility activity is discussed further in the MD&A section of this 10-Q report under the caption "Non-Current Borrowings – Maximilian Loan."

Results of Operations – Nine Months Ended November 30, 2014 compared to the Nine Months Ended November 30, 2013

California Oil Sales

For the nine months ended November 30, 2014, the average WTI price was $94.79 and our average realized sale price was $89.10 representing a discount of $5.69 per barrel or 6.0% lower than the average WTI price. In comparison, for the nine months ended November 30, 2013, the average WTI price was $98.57 and our average realized sale price was $96.63, representing a discount of $1.94 per barrel or 2.0% lower than the average WTI price. Historically, the sale price we receive for California heavy oil has been less than the quoted WTI price because of the lower API gravity of our California oil in comparison to WTI oil API gravity. However, from March of 2011 through May of 2013, we did receive a premium for our California oil in comparison to the WTI price. We are unable to forecast if we will again receive a premium for our oil in comparison to the WTI price as there are many factors beyond our control that dictate the price we receive for our oil.

Kentucky Oil Sales

Our first oil sales in Kentucky occurred in October 2013. For the nine months ended November 30, 2014, our average realized sale price was $95.48 in comparison to the average WTI price of $94.79 representing a premium of $0.69 per barrel or 0.7% from the average WTI price. In comparison, for the nine months ended November 30, 2013 the average WTI price was $98.57 and our average realized sale price was $94.65, representing a discount of $3.92 per barrel or 4.0% lower than the average WTI price. We are unable to forecast how long we will continue to receive a premium for our Kentucky oil sales in comparison to the WTI price as there are many factors beyond our control that dictate the price we receive on our oil sales.

Kentucky Natural Gas Sales

Our first natural gas sales in Kentucky also occurred in October 2013. For the nine months ended November 30, 2014, our average realized sale price was $3.01 per Mcf in comparison to the average Henry Hub price of $$4.28 per million BTU representing a discount of $1.27 per Mcf or 29.7% lower than the average Henry Hub price. In comparison, for the nine months ended November 30, 2013, the average realized sale price was $2.13 per Mcf while the average Henry Hub price was $3.76 per million BTU representing a discount of $1.63 or 43.4% lower than the average Henry Hub price.

Our oil and natural gas revenues for the nine months ended November 30, 2014 and November 30, 2013 are set forth in the table below:

	Nine Months Ended November 30, 2014		Nine Months Ended November 30, 2013	
Project	**Sales Revenue**	**Percentage**	**Sales Revenue**	**Percentage**
California – East Slopes Project (Oil)	$ 1,122,860	44.6%	$ 1,046,612	92.5%
Kentucky – Twin Bottoms Field (Oil)	1,356,180	53.8%	83,600	7.4%
Kentucky – Twin Bottoms Field (Natural gas)	39,335	1.6%	1,635	0.1%
	$ 2,518,375	100.0%	$ 1,131,847	100.0%

Revenues for the nine months ended November 30, 2014 increased $1,386,528 or 122.5% to $2,518,375 in comparison to revenues of $1,131,847 for the nine months ended November 30, 2013. In California, oil revenues increased $76,248 or 7.3% despite a decrease in the average realized sales price of $7.53 or 7.8% from $96.63 per barrel to $89.10 per barrel for the nine months ended November 30, 2014. In Kentucky, oil revenues increased $1,272,580 to $1,356,180 since only one well was on production for the nine months ended November 30, 2013. Natural gas revenues increased $37,700 to $39,335 also due to 10 wells on production for the nine months ended November 30, 2014. The average realized sales price of all hydrocarbon sales in California and Kentucky on a BOE basis for the nine months ended November 30, 2014 was $86.78 in comparison to $95.56 for the nine months ended November 30, 2013.

Our net production volume in California for the nine months ended November 30, 2014 was 12,602 barrels of oil in comparison to 10,831 barrels for the nine months ended November 30, 2013. In Kentucky, production for the nine months ended November 30, 2014 was 16,428 BOE from 10 wells in comparison to 1,047 BOE from one well for the nine months ended November 30, 2013. Average daily production was 106 BOE in aggregate; 46 BOE per day in California and 60 BOE per day in Kentucky.

Operating Expenses. Total operating expenses including non-cash DD&A for the nine months ended November 30, 2014 decreased by $102,699 or 6.2% to $1,548,127 in comparison to $1,650,826 for the nine months ended November 30, 2013. On a BOE basis, total operating expenses for the nine months ended November 30, 2014 decreased $85.65 per barrel or 61.6% to $53.33 in comparison to $138.98 per barrel for the nine months ended November 30, 2013.

Operating expenses for the nine months ended November 30, 2014 and November 30, 2013 are set forth in the table below:

	Nine Months Ended November 30, 2014		Nine Months Ended November 30, 2013	
	Expenses	**Percentage**	**Expenses**	**Percentage**
Production expenses	$ 251,625	16.3%	$ 160,652	9.7%
Exploration and drilling expenses	20,172	1.3%	245,685	14.9%
Depreciation, Depletion, Amortization, and Impairment (“DD&A”)	426,366	27.5%	261,641	15.8%
Write down on asset disposal	-	-	39,254	2.4%
General and Administrative (“G&A”) expenses	849,964	54.9%	943,594	57.2%
Total operating expenses	$ 1,548,127	100.0%	$ 1,650,826	100.0%

For the nine months ended November 30, 2014, production expenses increased by $90,973 or 56.6% to $251,625 in comparison to $160,652 for the nine months ended November 30, 2013. This increase in production expenses is primary due to the addition of nine new horizontal oil wells in Kentucky. For the nine months ended November 30, 2014 we had 20 wells on production in California and 10 wells on production in Kentucky in comparison to 20 wells in California and one in Kentucky for the nine months ended November 30, 2013. On a BOE basis production expenses in California were $11.51 per barrel for the nine months ended November 30, 2014 in comparison to $14.77 per barrel for the nine months ended November 30, 2013. In Kentucky, on a BOE basis, production expenses were $6.49 per barrel for the nine months ended November 30, 2014 in comparison to $0.77 per barrel for one well during the nine months ended November 30, 2013. Combined LOE for both California and Kentucky on a BOE basis was $8.67 per barrel for the nine months ended November 30, 2014 in comparison to $13.53 per barrel for the nine months ended November 30, 2013. Production expenses represented 16.3% of total operating expenses.

Production expenses for California and Kentucky for the nine months ended November 30, 2014 and November 30, 2013 are set forth in the table below:

	Nine Months Ended November 30, 2014		**Nine Months Ended November 30, 2013**	
	Expenses	**Percentage**	**Expenses**	**Percentage**
California – East Slopes Project	$ 144,992	57.6%	$ 159,845	99.5%
Kentucky – Twin Bottoms Field	106,633	42.4%	807	0.5%
Total production expenses	$ 251,625	100.0%	$ 160,652	100.0%

For the nine months ended November 30, 2014 exploration and drilling expenses decreased $225,513 or 91.8% to $20,172 in comparison to $245,685 for the nine months ended November 30, 2013. The primary reason for the decrease in exploration and drilling expenses was due to recognition of dry hole expenses in California for the nine months ended November 30, 2013. There was no dry hole expense for the nine months ended November 30, 2014. Exploration and drilling expenses represented 1.3% of total operating expenses.

For the nine months ended November 30, 2014, DD&A expenses increased $164,725 or 63.0% to $426,366 in comparison to $261,641 for the nine months ended November 30, 2013. The increase in DD&A is directly related to our involvement in the Twin Bottoms Field in Kentucky and the depletion of those associated reserves where 10 wells were on production for the nine months ended November 30, 2014 in comparison to one well on production for the nine months ended November 30, 2013. On a BOE basis, DD&A and impairment represented $14.69 and $22.03 per barrel for the nine months ended November 30, 2014 and 2103, respectively. DD&A expenses represented 27.5% of total operating expenses.

For the nine months ended November 30, 2014 G&A expenses decreased $93,630 or 9.9% to $849,964 in comparison to $943,594 for the nine months ended November 30, 2013. Travel expenses decreased $32,400 because of the decrease in drilling activity during the nine months ended November 30, 2014 in comparison to the nine months ended November 30, 2013. Additionally, director fees decreased $33,900 due to fewer individuals on the Board of Directors of the Company. Advertising, marketing and press release expenses decreased by approximately $26,100. Consulting fees for SOX 404 compliance were reduced by $18,600. For the nine months ended November 30, 2014, we received, as Operator in California, administrative overhead reimbursement of $49,173 for the East Slopes Project which was used to directly offset certain employee salaries. We are continuing a program of reducing all of our G&A costs wherever possible. G&A expenses represented 54.9% of total operating expenses for the nine months ended November 30, 2014.

Interest income for the nine months ended November 30, 2014 increased $698,047 to $833,778 in comparison to $135,731 for the nine months ended November 30, 2013 primarily due to interest income earned on the Note receivable from App Energy. For further discussion on this Note refer to the App Loan Agreement under Long-term Financing section in this MD&A.

Interest expense for the nine months ended November 30, 2014 increased $1,135,294 to $2,081,590 in comparison to $946,296 for the nine months ended November 30, 2013. The increase in interest expense was primarily from higher loan balances on our credit facility due to drilling program and lending activities in Kentucky, and the acquisition of our common stock shares from Maximilian. The credit facility activity is discussed further in the MD&A section of this 10-Q report under the caption “Non-Current Borrowings – Maximilian Loan.”

Due to the nature of our business, we expect that revenues, as well as all categories of expenses, will continue to fluctuate substantially on a quarter-to-quarter and year-to-year basis. Production expenses and revenues will fluctuate according to the number and percentage ownership of producing wells as well as the amount of revenues we receive based on the price of oil. Exploration and drilling expenses will be dependent upon the amount of capital that we have to invest in future development projects, as well as the success or failure of such projects. Likewise, the amount of DD&A expense will depend upon the factors cited above including the size of our proven reserves base and the market price of energy products. G&A expenses will also fluctuate based on our current requirements, but will generally tend to increase as we expand the business operations of the Company. An ongoing goal of the Company is to improve cash flow to cover the current level of G&A expenses and to fund our development drilling programs in California and Kentucky.

Capital Resources and Liquidity

Our primary financial resource is our proven oil reserves base. Our ability to fund any future capital expenditure programs is dependent upon the prices we receive from oil sales, the success of our exploration and development program in Kern County, California and Lawrence County, Kentucky and the availability of capital resource financing. We plan to resume our drilling activities in both California and Kentucky once the price of oil improves. However, our actual expenditures may vary significantly if our exploration and development plans change during the year or financing is unavailable. Factors such as changes in operating margins and the availability of capital resources could increase or decrease our ultimate level of expenditures during the next fiscal year.

Changes in our capital resources at November 30, 2014 in comparison to February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014	Increase (Decrease)	Percentage Change
Cash	$ 521,026	$ 500,431	$ 20,595	4.1%
Current Assets	$ 3,551,703	$ 2,142,887	$ 1,408,816	65.7%
Total Assets	$ 13,429,130	$ 10,677,910	$ 2,751,220	25.8%
Current Liabilities	$ 7,314,126	$ 6,834,937	$ 479,189	7.0%
Total Liabilities	$ 18,214,860	$ 13,486,654	$ 4,728,206	35.1%
Working Capital Deficit	$ (3,762,423)	$ (4,692,050)	$ (929,627)	(19.8)%

Our working capital deficit decreased $929,627 or 19.8% to $3,762,423 at November 30, 2014 in comparison to $4,692,050 at February 28, 2014. This decrease in the working capital deficit was primarily due to an increase in revenue from the additional six horizontal oil wells that were put on production in Kentucky during the nine months ended November 30, 2014. While we have ongoing positive cash flow from our operations in California and Kentucky we have not yet been able to generate sufficient cash flow to cover all of our G&A and interest expense requirements on a consistent basis. We anticipate an increase in our cash flow from our operations in Kern County, California and Lawrence County, Kentucky during the current fiscal year will contribute to the continuing reduction in our working capital deficit and improved net profit results despite lower hydrocarbon prices.

Our business is capital intensive. Our ability to grow is dependent upon favorably obtaining outside capital and generating cash flows from operating activities necessary to fund our investment activities. There is no assurance that we will be able to achieve sustained profitability. Since our future operations will continue to be dependent on successful exploration and development activities and our ability to seek and secure capital from external sources, should we be unable to achieve sustainable profitability this could cause any equity investment in the Company to become worthless.

Major sources of funds in the past for us have included the debt or equity markets and the sale of assets. While we have achieved positive cash flow from operations in California and Kentucky, we will have to rely on these capital markets to fund future operations and growth. Our business model is focused on acquiring exploration or development properties as well as existing production. Our ability to generate future revenues and operating cash flow will depend on successful exploration, and/or acquisition of oil and gas producing properties, which may very likely require us to continue to raise equity or debt capital from outside sources.

Daybreak has ongoing capital commitments to develop certain leases pursuant to their underlying terms. Failure to meet such ongoing commitments may result in the loss of the right to participate in future drilling on certain leases or the loss of the lease itself. These ongoing capital commitments may also cause us to seek additional capital from sources outside of the Company. The current uncertainty in the credit and capital markets, and the economic downturn, may restrict our ability to obtain needed capital.

The Company's financial statements for the nine months ended November 30, 2014 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. Since entering the oil and gas exploration industry, we have mostly incurred quarterly net losses. As of November 30, 2014, we have an accumulated deficit of $27,750,137 and a working capital deficit of $3,762,423 which raises substantial doubt about our ability to continue as a going concern.

In the current fiscal year, we will continue to seek additional financing for our planned exploration and development activities in both California and Kentucky. We plan to obtain financing through various methods, including issuing debt securities, equity securities, bank debt, or combinations of these instruments which could result in dilution to existing security holders and increased debt and leverage. No assurance can be given that we will be able to obtain funding under any loan commitments or any additional financing on favorable terms, if at all. Sales of interests in our assets may be another source of cash flow.

Cash Flows

Changes in the net funds provided by and (used in) our operating, investing and financing activities are set forth in the table below:

	Nine Months November 30, 2014	Nine Months November 30, 2013	Increase (Decrease)	Percentage Change
Net cash provided by (used in) operating activities	$ 254,645	$ (1,081,440)	$ 1,336,085	123.5%
Net cash (used in) investing activities	$ (3,387,719)	$ (3,931,295)	$ (543,576)	(13.8%)
Net cash provided by financing activities	$ 3,153,669	$ 5,127,429	$ (1,973,760)	(38.5%)

Cash Flow Provided by (Used In) Operating Activities

Cash flow from operating activities is derived from the production of our oil and gas reserves and changes in the balances of non-cash accounts, receivables, payables or other non-energy property asset account balances. For the nine months ended November 30, 2014, we had a positive cash flow from operating activities of $254,645 in comparison to a cash flow deficit of ($1,081,440) for the nine months ended November 30, 2013. This is an improvement of $1,336,085 in our cash flow from our operating activities for the nine months ended November 30, 2014. Non-cash account balances relating to DD&A; amortization of debt discount and deferred financing costs; and stock compensation accounted for an increase of $872,903 for the nine months ended November 30, 2014. Changes in our receivables and prepaid balances accounted for a net increase of $69,784 in our cash flow for the nine months ended November 30, 2014. Changes in our liability balances accounted for a net decrease of $410,478 for the nine months ended November 30, 2014. Variations in cash flow from operating activities may impact our level of exploration and development expenditures.

Cash Flow (Used in) Investing Activities

Cash flow from investing activities is derived from changes in oil and gas property balances and our lending activities associated with the App Energy loan. Cash used in investing activities for the nine months ended November 30, 2014 was $3,387,719, a decrease of $543,576 from the $3,931,295 used in investing activities for the nine months ended November 30, 2013. This decrease was primarily due to a lower degree of drilling activity in comparison to the nine months ended November 30, 2013. Net advances to App Energy through the credit facility for Kentucky drilling during the nine months ended November 30, 2014 were $1,918,290. During the nine months ended November 30, 2014, in connection with amended our credit facility with Maximilian, we also amended the terms of the App Energy loan to eliminate App Energy's right under the original loan agreement to waive up to three required monthly payments. Refer to Note 9 – Note Receivable for further discussion of the App Energy loan.

Cash Flow Provided by Financing Activities

Cash flow from financing activities is derived from changes in long-term liability account balances or in equity account balances, excluding retained earnings. Cash provided by our financing activities was approximately $3.2 million for the nine months ended November 30, 2014 in comparison to cash used in our financing activities of approximately $5.1 million for the nine months ended November 30, 2013. We received advances on our loan commitment for drilling activities in California and Kentucky of approximately $5.7 million in aggregate offset by payments on our credit line, note payable and deferred financing fees.

The following discussion is a summary of cash flows provided by, and used in, the Company's financing activities at November 30, 2014.

Short-term Borrowings (Current Debt)

Related Party

During the years ended February 29, 2012 and February 28, 2013, the Company's President and Chief Executive Officer loaned the Company $250,100 in aggregate that has been used for a variety of corporate purposes including an escrow requirement on a loan commitment; extension fees on third party loans; and, a reduction of principal on the Company's credit line with UBS Bank. These loans are non-interest bearing loans and repayment will be made upon a mutually agreeable date in the future.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. At November 30, 2014 the Line of Credit had an outstanding balance of $876,948. Interest is payable monthly at a stated reference rate of 0.249% + 337.5 basis points and totaled $23,581 for the nine months ended November 30, 2014. The reference rate is based on the 30 day LIBOR ("London Interbank Offered Rate") and is subject to change from UBS.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a March 2010 private placement, resulted in $595,000 in gross proceeds (of which $250,000 was issued to a related party) to the Company and accrues interest at 12% per annum, payable semi-annually on January 29th and July 29th. The note principal is payable in full at the maturity of the Notes, which is January 29, 2015. Should the Board of Directors, on the maturity date, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company's common stock at a conversion rate equal to 75% of the average closing price of the Company's common stock over the 20 consecutive trading days preceding December 31, 2014.

In conjunction with the Notes private placement, a total of 1,190,000 common stock purchase warrants were issued at a rate of two warrants for every dollar raised through the private placement. The warrants have an exercise price of $0.14 and expire on January 29, 2015. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $116,557 using the following weighted average assumptions: a risk free interest rate of 2.33%; volatility of 147.6%; and dividend yield of 0.0%. The fair value of the warrants was recognized as a discount to debt and is being amortized over the term of the Notes using the effective interest method. Amortization expense was $23,784 for the nine months ended November 30, 2014.

For the nine months ended November 30, 2014, one 12% Subordinated noteholder exercised the warrants associated with the 12% Note. A total of 50,000 warrants were exercised and resulted in 50,000 shares of common stock being issued to the noteholder.

The 12% Note warrants that have been exercised are set forth in the table below.

Fiscal Period	Warrants Exercised	Shares of Common Stock Issued	Number of Accredited Investors
Year Ended February 28, 2014	100,000	100,000	1
Nine Months Ended November 30, 2014	50,000	50,000	1
Totals	**150,000**	**150,000**	**2**

Current Notes balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
12% Subordinated Notes	$ 345,000	$ 345,000
12% Subordinated Notes discount	(3,428)	(17,129)
	$ 341,572	$ 327,871

Current Notes, related party balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
12% Subordinated Notes, related party	$ 250,000	$ 250,000
12% Subordinated Notes discount, related party	(2,522)	(12,605)
	$ 247,478	$ 237,395

Long-term Borrowings (Non-current Debt)

Maximilian Loan

On October 31, 2012, the Company entered into a loan agreement with Maximilian, which provided for a revolving credit facility of up to $20 million, maturing on October 31, 2016, with a minimum commitment of $2.5 million. The loan had annual interest of 18% and a monthly commitment fee of 0.5%. The Company also granted Maximilian a 10% working interest in its share of the oil and gas leases in Kern County, California. The relative fair value of this 10% working interest amounting to $515,638 was recognized as a debt discount and is being amortized over the term of the loan. Amortization expense was $104,176 for the nine months ended November 30, 2014.

The Company also issued 2,435,517 warrants to third parties who assisted in the closing of the loan. The warrants have an exercise price of $0.044; contain a cashless exercise provision; have piggyback registration rights; and are exercisable for a period of five years expiring on October 31, 2017. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $98,084 and included the following assumptions: a risk free interest rate of 0.72%; stock price of $0.04, volatility of 153.44%; and a dividend yield of 0.0%. The fair value of the warrants was recognized as a financing cost and is being amortized as a part of deferred financing cost over the term of the loan. On March 10, 2014, one of the third parties exercised 2,118,900 warrants resulting in the issuance of 1,873,554 shares of the Company's common stock.

Maximilian Loan - Amended and Restated Loan Agreement

In connection with the Company's acquisition of a working interest from App in the Twin Bottoms Field in Lawrence County, Kentucky, the Company amended its loan agreement with Maximilian on August 28, 2013. The amended loan agreement provided for an increase in the revolving credit facility from $20 million to $90 million and a reduction in the annual interest rate from 18% to 12%. The monthly commitment fee of 0.5% per month on the outstanding principal balance remained unchanged. Advances under the amended loan agreement will mature on August 28, 2017. The obligations under the amended loan agreement continue to be secured by a perfected first priority security interest in substantially all of the personal property of the Company, and a mortgage on the Company's leases in Kern County, California. The amended loan agreement also provided for the revolving credit facility to be divided into two borrowing sublimits. The first borrowing sublimit is $50 million and is for borrowing by the Company, primarily for its ongoing oil and gas exploration and development activities. The second borrowing sublimit, of $40 million, is for loans to be extended by the Company, as lender, to App, as borrower pursuant to a Loan and Security Agreement entered into between the Company and App on August 28, 2013 (See Note 9 – Note Receivable).

The amended loan agreement contains customary covenants for loan of such type, including among other things, covenants that restrict the Company's ability to make capital expenditures, incur indebtedness, incur liens and dispose of property. The amended loan agreement also contains various events of default, including failure to pay principal and interest when due, breach of covenants, materially incorrect representations and bankruptcy or insolvency. If an event of default occurs, all of the Company's obligations under the amended loan agreement could be accelerated by Maximilian, causing all loans outstanding (including accrued interest and fees payable thereunder) to be declared immediately due and payable.

As consideration for Maximilian facilitating the Company's transactions with App and entering into the amended loan agreement, the Company (a) issued to Maximilian approximately 6.1 million common shares, representing 9.99% of the Company's outstanding common stock on a fully-diluted basis at the time of grant, and (b) issued approximately 6.1 million warrants to purchase shares of the Company's common stock representing the right to purchase up to an additional 9.99% of the Company's outstanding common stock on a fully-diluted basis, calculated as of the date of grant. The warrants have an exercise price of $0.10; contain a cash exercise provision and are exercisable for a period of three years expiring on August 28, 2016; and contain an exercise blocker provision that prevents any exercise of the warrants if such exercise and related issuance of common stock would increase the Maximilian holdings of the Company's common stock to more than 9.99% of the Company's currently issued and outstanding shares at the time of the exercise. The Company also granted to Maximilian a 50% net profits interest in the Company's 25% working interest, after the Company recovers its investment, in the Company's working interest in its Kentucky acreage, pursuant to an Assignment of Net Profits Interest entered into as of August 28, 2013 by and between the Company and Maximilian.

On May 28, 2014 at Maximilian's request, the Company finalized a share-for-warrant exchange agreement in which Maximilian returned to the Company 427,729 common shares and was in turn issued the same number of warrants containing the same provisions as the originally issued warrants. This share-for-warrant exchange occurred so that Maximilian would hold no more than 9.99% of the Company's common shares issued and outstanding. The Company determined that the share-for-warrant exchange did not result in any incremental fair value.

On August 21, 2014, the Company entered into a First Amendment to Amended and Restated Loan and Security Agreement and Share Repurchase Agreement (the "Amendment") with Maximilian under its Amended and Restated Loan and Security Agreement dated as of August 28, 2013. The Amendment secured for the Company an additional advance of $2,200,000 under its credit facility with Maximilian since the advances made by Maximilian had already exceeded its minimum funding commitment. Additionally, Maximilian agreed to temporarily decrease the required monthly payment made by the Company until a savings of $1,000,000 was realized by the Company. As of November 30, 2014, the Company had recognized $700,000 of the reduced monthly principal payments program. The combined $3,200,000 in additional capital will be used by the Company for additional development well drilling on its Twin Bottoms Field acreage in Kentucky and to loan funds to App, its Kentucky drilling partner, for its portion of the development well drilling. Furthermore, Maximilian agreed to reduce the regular interest rate applicable to the loan from 12% per annum to 9% per annum and the default interest rate by 3%.

The additional advance, the reduction in the required monthly payment and the reduction in the interest rate were facilitated through our acquisition of 5,694,823 shares of our common stock held by Maximilian. The repurchased shares were cancelled and restored to the status of authorized, but unissued stock. We paid for the share repurchase transaction through an advance of $1,708,447 under the existing loan agreement with Maximilian.

During the nine months ended November 30, 2014, the Company received multiple advances from Maximilian of approximately $7.4 million in aggregate that were used to participate in the multi-well drilling program at the Twin Bottoms Field in Kentucky; to advance of funds to App through a long-term note receivable; and, to fund the acquisition referenced in the prior paragraph of the Company's common stock from Maximilian. The Company made principal payments of approximately $2.2 million to Maximilian during the nine months ended November 30, 2014. The Company has recognized $154,559 in deferred financing costs associated with these advances which are being amortized over the amended term of the revolving credit facility.

Current debt balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Maximilian Note	$ 3,224,918	$ 2,163,405
Maximilian Note Discount	(135,709)	(138,988)
	$ 3,089,209	$ 2,024,417

Non-current debt balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Maximilian Note	$ 10,977,727	$ 6,833,703
Maximilian Note Discount	(103,168)	(204,065)
	$ 10,874,559	$ 6,629,638

App Loan Agreement

In connection with amending and restating its loan agreement with Maximilian, on August 28, 2013 the Company extended to App Energy, LLC, a Kentucky limited liability company ("App") a credit facility for the development of a shallow oil project in an existing gas field in Lawrence County, Kentucky pursuant to a Loan and Security Agreement between the Company as lender and App as borrower (the "App Loan Agreement").

The App Loan Agreement provides for a revolving credit facility of up to $40 million, maturing on August 28, 2017, with a minimum commitment of $2.65 million (the "Initial Advance"). All funds advanced to App, as borrower, by Daybreak, as lender, are to be borrowed by Daybreak under its Amended Loan Agreement with Maximilian. The Initial Advance bears interest at a rate per annum equal to 16.8%, and subsequent loans under the Loan Agreement bear interest at a rate per annum equal to 12%. The App Loan Agreement also provides for a monthly commitment fee of 0.6% per month of the outstanding principal balance of the loans. The obligations under the App Loan Agreement are secured by a perfected first priority security interest in substantially all of the assets of App, including the App leases in Lawrence County, Kentucky.

The proceeds of the initial borrowing by App of $2.65 million under the App facility were primarily used to (a) pay loan fees and closing costs, (b) repay indebtedness and (c) finance the drilling of three wells by App in the Twin Bottoms Field in Lawrence County, Kentucky in which the Company has a 25% working interest. Future advances under the facility will primarily be used for oil and gas exploration and development activities.

The App Loan Agreement contains customary covenants for loan of such type, including, among other things, covenants that restrict App's ability to make capital expenditures, incur indebtedness, incur liens and dispose of property. The App Loan Agreement also contains various events of default, including failure to pay principal and interest when due, breach of covenants, materially incorrect representations and bankruptcy or insolvency. If an event of default occurs, all of App's obligations under the App Loan Agreement could be accelerated by the Company, causing all loans outstanding (including accrued interest and fees payable thereunder) to be declared immediately due and payable.

In connection with the App Loan Agreement, App also granted to the Company a 25% working interest in approximately 6,400 acres (currently 7,300 acres) in two large contiguous blocks in the Twin Bottoms Field in Lawrence County, Kentucky and entered into a corresponding promissory note and a Mortgage, Leasehold Mortgage, Assignment of Production, Security Agreement and Financing Statement, both dated as of August 28, 2013. App's manager, John A. Piedmonte, Jr., also entered into a limited Indemnity Agreement in connection with the loan. The loans under the App Loan Agreement are also guaranteed by certain of App's affiliates.

At November 30, 2014, the Company had advanced $8,312,500 million to App through its credit facility. Note receivable balances at November 30, 2014 and February 28, 2014 are set forth in the table below:

	November 30, 2014	February 28, 2014
Note receivable – current	$ 2,162,222	$ 793,727
Note receivable – non-current	3,306,068	2,756,273
	$ 5,468,290	$ 3,550,000

As of January 9, 2015, the Company had advanced an additional $37,500 since November 30, 2014 to App Energy, LLC through its credit facility with the Company.

Capital Commitments

Daybreak has ongoing capital commitments to develop certain leases pursuant to their underlying terms. Failure to meet such ongoing commitments may result in the loss of the right to participate in future drilling on certain leases or the loss of the lease itself. These ongoing capital commitments may also cause us to seek additional capital from sources outside of the Company. The current uncertainty in the credit and capital markets, and the economic downturn, may restrict our ability to obtain needed capital.

Encumbrances

The Company's debt obligations, pursuant to a loan agreement entered into by and between Maximilian as lender, and the Company are secured by a perfected first priority security interest in substantially all of the personal property of the Company, and a mortgage on our leases in Kern County, California encompassing the Sunday, Bear, Black, Ball and Dyer Creek properties. For further information on the loan agreement refer to the discussion under the caption "Long-Term Borrowings" in this MD&A.

Restricted Stock and Restricted Stock Unit Plan

On April 6, 2009, the Board approved the Restricted Stock and Restricted Stock Unit Plan (the "2009 Plan") allowing the executive officers, directors, consultants and employees of Daybreak and its affiliates to be eligible to receive restricted common stock and restricted common stock unit awards. Subject to adjustment, the total number of shares of Daybreak common stock that will be available for the grant of awards under the 2009 Plan may not exceed 4,000,000 shares; provided, that, for purposes of this limitation, any stock subject to an award that is forfeited in accordance with the provisions of the 2009 Plan will again become available for issuance under the 2009 Plan. We believe that awards of this type further align the interests of our employees and our shareholders by providing significant incentives for these employees to achieve and maintain high levels of performance. Restricted stock and restricted stock units also enhance our ability to attract and retain the services of qualified individuals.

At November 30, 2014, a total 3,000,000 shares were awarded and are fully vested, with 2,986,220 shares of restricted stock that remain outstanding and are fully vested under the 2009 Plan. A total of 1,013,780 common stock shares remained available at November 30, 2014 for issuance pursuant to the 2009 Plan. A summary of the 2009 Plan issuances is set forth in the table below:

Grant Date	Shares Awarded	Vesting Period	Shares Vested(1)	Shares Returned(2)	Shares Outstanding (Unvested)
4/7/2009	1,900,000	3 Years	1,900,000	-	-
7/16/2009	25,000	3 Years	25,000	-	-
7/16/2009	625,000	4 Years	619,130	5,870	-
7/22/2010	25,000	3 Years	25,000	-	-
7/22/2010	425,000	4 Years	417,090	7,910	-
	3,000,000		2,986,220(1)	13,780(2)	-

(1) Does not include shares that were withheld to satisfy such tax liability upon vesting of a restricted award by a Plan Participant, and subsequently returned to the 2009 Plan.

(2) Reflects the number of common shares that were withheld pursuant to the settlement of the number of shares with a fair market value equal to such tax withholding liability, to satisfy such tax liability upon vesting of a restricted award by a Plan Participant.

For the nine months ended November 30, 2014, the Company recognized compensation expense related to the above restricted stock grants in the amount of $2,515. For the nine months ended November 30, 2014, there were 2,040 shares of the Company's common stock relating to the 2009 Plan that were returned to the 2009 Plan to satisfy an employee's payroll tax liability upon the vesting of the shares relating to the 2009 Plan.

Management Plans to Continue as a Going Concern

We continue to implement plans to enhance Daybreak's ability to continue as a going concern. The Company currently has a net revenue interest in 20 producing oil wells in its East Slopes Project located in Kern County, California (the "East Slopes Project"). The revenue from these wells has created a steady and reliable source of revenue. The Company's average working interest in these wells is 36.6% and the average net revenue interest is 28.4%.

Additionally, we have become involved in a shallow oil play in an existing natural gas field in Lawrence County, Kentucky, through our acquisition of a 25% working interest in approximately 7,300 acres in two large contiguous acreage blocks in the Twin Bottoms Field in Lawrence County, Kentucky. We had 10 horizontal oil wells on production in Kentucky during portions of the nine months ended November 30, 2014 and have brought three additional horizontal oil wells onto production in December 2014. We are in the process of completing and bringing onto production an additional four horizontal oil wells also in Kentucky. Our average working interest in these 13 wells is 22.4% and the average net revenue interest is 19.6%.

We anticipate revenues will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project in California and the Twin Bottoms Field in Kentucky. The Company plans to continue its development drilling program at a rate that is compatible with its cash flow and funding opportunities.

The Company's sources of funds in the past have included the debt or equity markets and the sale of assets. While the Company has experienced revenue growth from its oil properties, we have not yet established a positive cash flow on a company-wide basis. It will be necessary for the Company to obtain additional funding from the private or public debt or equity markets in the future. However the Company cannot offer any assurance that the Company will be successful in executing the aforementioned plans to continue as a going concern.

Critical Accounting Policies

Refer to Daybreak's Annual Report on Form 10-K for the fiscal year ended February 28, 2014.

Off-Balance Sheet Arrangements

As of November 30, 2014, we did not have any off-balance sheet arrangements or relationships with unconsolidated entities or financial partners that have been, or are reasonably likely to have, a material effect on our financial position or results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

ITEM 4. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As of the end of the reporting period, November 30, 2014, an evaluation was conducted by Daybreak management, including our President and Chief Executive Officer, who is also serving as our interim principal finance and accounting officer, as to the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(e) of the Exchange Act. Such disclosure controls and procedures are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods specified by the SEC rules and forms. Additionally, it is vital that such information is accumulated and communicated to our management, including our President and Chief Executive Officer, in a manner to allow timely decisions regarding required disclosures. Based on that evaluation, our management concluded that our disclosure controls were effective as of November 30, 2014.

Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the nine months ended November 30, 2014 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Limitations

Our management does not expect that our disclosure controls or internal controls over financial reporting will prevent all errors or all instances of fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Controls can also be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and any design may not succeed in achieving its stated goals under all potential future conditions.

Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with policies or procedures. Because of the inherent limitation of a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this Form 10-Q Report, you should carefully consider the various factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended February 28, 2014, which could materially affect our business, financial condition or future results. Our Annual Report is available from the SEC at www.sec.gov. The risks described in this report are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial could have a material adverse effect on our business, financial condition or future results of operations.

ITEM 6. EXHIBITS

The following Exhibits are filed as part of the report:

Exhibit Number	Description
31.1[(1)]	Certification of principal executive and principal financial officer as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1[(1)]	Certification of principal executive and principal financial officer as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS[(2)]	XBRL Instance Document
101.SCH[(2)]	XBRL Taxonomy Schema
101.CAL[(2)]	XBRL Taxonomy Calculation Linkbase
101.DEF[(2)]	XBRL Taxonomy Definition Linkbase
101.LAB[(2)]	XBRL Taxonomy Label Linkbase
101.PRE[(2)]	XBRL Taxonomy Presentation Linkbase

(1) Filed herewith.
(2) Furnished herewith

SIGNATURES

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

DAYBREAK OIL AND GAS, INC.

By: /s/ JAMES F. WESTMORELAND
James F. Westmoreland, its
President, Chief Executive Officer and interim
principal finance and accounting officer
(Principal Executive Officer, Principal Financial
Officer and Principal Accounting Officer)

Date: January 9, 2015