


# Q3 2014 MANAGEMENT'S DISCUSSION AND ANALYSIS

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") as provided by management of Spyglass Resources Corp. ("Spyglass" or the "Company") should be read in conjunction with the unaudited condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2014 and 2013 and the audited consolidated financial statements, related notes and Management's Discussion and Analysis for the years ended December 31, 2013 and 2012. This MD&A is dated as of November 13, 2014.

### Forward Looking Statements

Certain statements contained within the MD&A, and in certain documents incorporated by reference into this document constitute forward looking statements. These statements relate to future events or future performance. All statements, other than statements of historical fact, may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements.

In particular, this MD&A contains the following forward looking statements pertaining to, without limitation, the following: Spyglass' (i) future production volumes and the timing of when additional production volumes will come on stream; Spyglass' (ii) realized price of commodities in relation to reference prices; (iii) future commodity mix; (iv) future commodity prices; (v) expectations regarding future royalty rates and the realization of royalty incentives; (vi) expectation of future operating costs on a per unit basis; (vii) the relationship of Spyglass' interest expense and the Bank of Canada interest rates; (viii) future general and administrative expenses; future development and exploration activities and the timing thereof; (ix) deferred tax liability or tax asset; (x) estimated future contractual obligations; (xi) future liquidity and financial capacity of the Company; (xii) ability to raise capital and to add to reserves through exploration and development; (xiii) ability to obtain equipment in a timely manner to carry out exploration and development activities; (xiv) ability to obtain financing on acceptable terms, and (xv) ability to fund working capital and forecasted capital expenditures. In addition, statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve assessments based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

We believe the expectations reflected in the forward looking statements are reasonable but no assurance can be given that our expectations will prove to be correct and consequently, such forward looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference in this MD&A. The actual results could differ materially from those anticipated as a result of the risk factors set forth below and elsewhere in this MD&A which include: (i) volatility in market prices for oil and natural gas; (ii) counterparty credit risk; (iii) access to capital; (iv) changes or fluctuations in production levels; (v) liabilities inherent in oil and natural gas operations; (vi) uncertainties associated with estimating oil and natural gas reserves; (vii) competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; (viii) stock market volatility and market valuation of Spyglass' stock; (ix) geological, technical, drilling and processing capabilities; (x) limitations on insurance; (xi) changes in environmental or legislation applicable to our operations, and (xii) our ability to comply with current and future environmental and other laws; (xiii) changes in tax laws and incentive programs relating to the oil and gas industry, and (xiv) the other factors discussed under "Risk Factors" in the Company's 2013 Annual Information Form.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward looking statements contained in this document speak only as of the date of this document and Spyglass does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

### Basis of Presentation & Plan of Arrangement (the "Arrangement")

The financial data presented in this MD&A has been prepared in accordance with Part I of Canadian Generally Accepted Accounting Principles ("GAAP") or International Financial Reporting Standards ("IFRS") unless otherwise noted.

The reporting and the measurement currency is in Canadian dollars. For the purpose of calculating unit costs, natural gas is converted to a barrel equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The following MD&A compares the results of the nine months ended September 30, 2014 ("YTD 2014") to the nine months ended September 30, 2013

("YTD 2013") and the results of the three months ended September 30, 2014 ("Q3 2014") to the three months ended September 30, 2013 ("Q3 2013") and the three months ended June 30, 2014 ("Q2 2014").

On December 20, 2012, Pace Oil & Gas Ltd. ("Pace") entered into an arrangement agreement with Charger Energy Corp. ("Charger") and AvenEx Energy Corp. ("AvenEx"), pursuant to which Pace, Charger and AvenEx agreed to amalgamate by way of a plan of arrangement (the "Arrangement") to form Spyglass Resources Corp., an intermediate, dividend paying oil and gas producer.

On March 26, 2013, the shareholders of Pace, Charger and AvenEx approved the transaction and on March 28, 2013 the Arrangement was completed. Pace subdivided its shares on a basis of 1.3 post-subdivided Pace shares for each 1.0 pre-subdivided Pace share. 12,117,821 Pace shares were issued in exchange for the outstanding Charger shares on a basis of 0.18 Pace share for each Charger share. 54,967,543 Pace shares were issued in exchange for the outstanding AvenEx shares on a basis of 1.0 Pace share for each AvenEx share. Pace was then renamed Spyglass Resources Corp. which elected to perform a reduction of stated capital, whereby the Company offset its retained deficit, contributed surplus and accumulated other comprehensive loss against share capital. This resulted in 128,076,720 shares outstanding upon closing of the Arrangement, with a share capital of $494.3 million. Prior period common share information has been adjusted for the share exchange ratio associated with the Arrangement. The Transaction resulted in former Pace shareholders holding 48% of the combined outstanding common shares of Spyglass, the former AvenEx shareholders holding 43% and the former Charger shareholders holding 9% with the former management team of Charger becoming the new management team of Spyglass. The transaction was accounted for as an acquisition of AvenEx and Charger by Pace. Consideration was $150.3 million for net assets of $234.5 million resulting in gains on acquisition of $84.2 million. The financial statements and MD&A present the historical financial positions, results of operations and cash flows of Pace for all prior periods up to and including March 28, 2013. The results of operations after March 28, 2013 include Pace, AvenEx and Charger.

## 2014 Outlook and Operations Update

*Dixonville Update*

Spyglass continues to work with the Alberta Energy Regulator to return the Dixonville field to full production in a safe and appropriate manner as the Company completes a pipeline remediation program encompassing the oil emulsion gathering system. The capital for the pipeline system remediation, including liner installation, is expected to total $12 million. The source of the pipeline failures has been identified and is expected to be non-recurring. The remediated pipeline systems are expected to last for the economic life of the field.

Due to these incidents, 2014 average production at Dixonville (as compared to 2013 performance) is expected to be reduced by 900 boe/d. The related 2014 cash flow impact is approximately $13 million (as compared to 2013 performance), which includes $11 million of reduced cash flow from May 1, 2014 through to September 30, 2014.

To date, Spyglass has restarted approximately 70 percent (2,100 boe/d) of production with full capability expected to be reached late in the fourth quarter of 2014 or early in the first quarter of 2015.

*Halkirk-Provost Activity*

Spyglass commenced a horizontal drilling program in late July, targeting Viking light oil in the Halkirk, Brownstone and Neutral Hills areas of east central Alberta. To date, 8 of the 10 wells have been drilled and completed. Average drill, complete, equip and tie-in costs to date of $1.1 million per well represent an improvement of approximately 25 percent as compared to previous well cost estimates. The eight horizontal wells from the program have been on put production and early indications show a combined production rate of approximately 400 boe/d, with solution gas still being tied-in for two of the wells.

*Southern Alberta Activity*

Spyglass is extremely encouraged by the continued success of the horizontal wells drilled in southern Alberta targeting Glauconite and Pekisko/Banff oil on the Company's lands in the Matziwin and Cessford areas. Earlier this year, Spyglass upgraded its multi-well battery at Matziwin to accommodate future oil production from this growing area.

As a follow up to a successful Glauconite oil well drilled early in 2014, the Company drilled and completed an offsetting horizontal well and a step-out horizontal well at Cessford. These wells were tied-in and placed on production late in the third quarter. Production data will be released once stabilized rates have been achieved. The company is currently completing a 3-D seismic program in the area to further delineate and de-risk the play.

*Outlook*

Spyglass continues to focus on strengthening the balance sheet through non-core asset sales and developing the Company's drilling locations, while aligning the cost structure and dividend policy to the changing asset base. The Company will continue to pursue asset dispositions throughout the final quarter of 2014 and into 2015 to reduce debt and further focus operations. In the context of current commodity prices, Spyglass is developing its 2015 capital program recognizing the need to reduce leverage and allow the Company to continue to delineate the high impact, multi-zone oil opportunities emerging in its Southern Alberta core areas. Upon the successful completion of its 2014 asset disposition program, the Company will provide a board approved 2015 capital budget, 2015 guidance and dividend policy.

The 2014 capital program is expected to total approximately $77 million ($22 million, net of property dispositions closed up to September 30, 2014), incorporating the cost of the remediation program at Dixonville, with approximately 80 percent spent to September 30, 2014. Prior to year-end, an additional 2 gross (2.0 net) Viking wells are to be drilled in the Halkirk-Provost area.

Management anticipates that the Company's level of development activity and success in the 2014 drilling program, coupled with the Company's 20 percent base decline rate is expected to result in 2014 average production of approximately 14,000 boe/d. This takes into account year-to-date non-core property dispositions (approximately 500 boe/d) and shut-in production at Dixonville (approximately 900 boe/d, as compared to 2013 production). Management anticipates 2014 operating costs of approximately $20.00 per boe and general and administrative expenses of approximately $3.00 per boe prior to a $0.25 per boe provision for reorganization costs.

The current outlook for commodity prices coupled with Spyglass' net capital program, hedging position and current dividend level is expected to result in a 2014 target all-in payout ratio of approximately 85 percent.

## Non-GAAP Measurements

In the MD&A references are made to terms commonly used in the oil and gas industry. Funds from operations, funds from operations per share, netbacks, net debt, working capital deficit, basic payout ratio and all-in payout ratio are not defined by GAAP and are referred to as non-GAAP measures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income per share. Operating netback equals total revenue net of royalties and operating and transportation expenses calculated on a per boe basis. Cash flow netback equals operating netbacks described above and cash portion of other income, less cash general and administrative expenses, cash interest expenses and realized gain (loss) on financial derivative instruments. Cash flow and cash flow netbacks do not include transaction costs related to the Arrangement. Working capital (deficit) equals current assets less current liabilities. Net debt equals long-term debt and working capital (deficit) excluding current portion of financial derivative instruments and liabilities associated with assets held for sale. The basic payout ratio equals dividends declared divided by funds from operations. The all-in payout ratio equals dividends declared and capital expenditures (net of property dispositions) divided by funds from operations. Management utilizes these measures to analyze operating performance and leverage. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations is commonly referred to as cash flow by research analysts and is used to value and compare oil and gas companies and is frequently included in published research when providing investment recommendations. Total boes are calculated by multiplying the average daily production by the number of days in the period.

The following table reconciles cash flow from operating activities to funds from operations which is used in the MD&A:

| ($000s) | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| Cash flow from operating activities | **$ 8,398** | $ 14,046 | $ 27,470 | **$ 46,210** | $ 12,201 |
| Transaction costs | **-** | - | - | **-** | 13,451 |
| Decommissioning expenditures | **516** | 497 | 729 | **3,616** | 2,549 |
| Change in non-cash working capital | **2,988** | 7,004 | (9,156) | **(2,855)** | 20,957 |
| Funds from operations | **$ 11,902** | $ 21,547 | $ 19,043 | **$ 46,971** | $ 49,158 |

## Production

The Company categorizes and manages its production in three core areas: North, Central and South with a breakdown of production by product and by area provided in the following tables. Total company production for Q3 2014 averaged 13,518 boe/d compared to 14,474 in Q2 2014 and 16,445 in Q3 2013.

Drilling activity in the quarter included an 8 gross (8.0 net) well drilling program in the Halkirk-Provost area and a 2 gross (2.0 net) well drilling program in Cessford. The Cessford wells came on production late in Q3 2014 and production data will be released once stabilized rates have been achieved. The Halkirk-Provost wells came on production in late September to early October with a combined 30 day initial production rate of 400 boe/d, but given the timing, had a minimal impact on Q3 2014 production. The successful Q3 2014 drilling program is expected to contribute on average approximately 700 boe/d of production in Q4 2014. Non-core property dispositions in Q3 2014 were weighted towards natural gas (87%) and decreased production by approximately 300 boe/d in Q3 2014 and are expected to decrease production by approximately 900 boe/d in Q4 2014, primarily in the North.

Oil and liquids production in Q3 2014 at 40% of total production is 8% lower than Q3 2013 and 6% lower than the oil and liquids weighting in Q2 2014. Q3 2014 oil and liquids production of 5,455 bbls/d is a decrease of 1,244 bbls/d or 19% from 6,699 bbls/d in Q2 2014 and a decrease of 2,401 bbls/d or 31% from 7,856 bbls/d in Q3 2013. The majority of the reported oil and liquids production decrease in Q3 2014 over Q2 2014 occurred in the Dixonville area with work continuing on pipeline remediation as more fully described in the "Environmental Liabilities, Insurance Receivable and Dixonville Pipeline Incidents" section. Throughout Q3 2014, the Company progressed on the pipeline remediation and has been bringing back production at Dixonville in stages as the work is completed. The downtime at Dixonville throughout the quarter resulted in decreases to Dixonville oil production of approximately 1,770 bbls/d compared to Q3 2013. As of the date of the MD&A approximately 70% or 2,100 boe/d of production is flowing and the Company expects that pending consultation with the AER, the inspection and remediation of the gathering system will be completed and Dixonville production will be fully restored by the end of 2014. The Dixonville incidents are expected to impact 2014 annualized production by approximately 900 boe/d when compared to 2013 performance.

Natural gas production for Q3 2014 averaged 48.4 MMcf/d, an increase of 1.8 MMcf/d or 4% from 46.6 MMcf/d in Q2 2014 and a decrease of 3.2 MMcf/d or 6% from Q3 2013. The increase in gas production from Q2 2014 relates primarily to the Noel horizontal gas well which was tied-in in July with 30 day initial production rates of 1,100 boe/d offset by non-core property dispositions which closed in the quarter and natural production declines.

YTD 2014 production averaged 14,180 boe/d, down 813 boe/d from 14,993 boe/d reported in YTD 2013. Oil and liquids production decreased 880 bbls/d while gas production decreased 0.4 MMcf/d. The majority of the decrease reflects the Dixonville pipeline incidents, production associated with property dispositions and natural declines, partially offset by production added through drilling activities.

For 2014, incorporating the Company's low decline rate, drilling success, non-core dispositions, a $77 million capital budget ($22 million net of property dispositions closed as at September 30, 2014) and shut-in production at Dixonville, production is anticipated to average approximately 14,000 boe/d.

The following table outlines production volumes for the periods indicated below:

| **Production** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| Oil (bbls/d) | **5,045** | 7,473 | 6,164 | **5,991** | 6,933 |
| NGLs (bbls/d) | **410** | 383 | 535 | **446** | 384 |
| Natural Gas (Mcf/d) | **48,379** | 51,533 | 46,647 | **46,460** | 46,057 |
| Total (boe/d) | **13,518** | 16,445 | 14,474 | **14,180** | 14,993 |
| Oil & Liquids weighting | **40%** | 48% | 46% | **45%** | 49% |

The following table sets out production volumes by core area:

| | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| **North** | | | | | |
| Oil (bbls/d) | **1,984** | 4,187 | 2,949 | **2,880** | 4,080 |
| NGLs (bbls/d) | **145** | 197 | 255 | **192** | 218 |
| Natural Gas (Mcf/d) | **30,272** | 33,398 | 29,295 | **29,237** | 29,785 |
| Total (boe/d) | **7,174** | 9,950 | 8,087 | **7,945** | 9,262 |
| **Central** | | | | | |
| Oil (bbls/d) | **603** | 666 | 601 | **595** | 482 |
| NGLs (bbls/d) | **104** | 72 | 128 | **106** | 48 |
| Natural Gas (Mcf/d) | **4,108** | 4,755 | 4,917 | **4,520** | 3,162 |
| Total (boe/d) | **1,392** | 1,531 | 1,549 | **1,454** | 1,057 |
| **South** | | | | | |
| Oil (bbls/d) | **2,458** | 2,620 | 2,614 | **2,516** | 2,371 |
| NGLs (bbls/d) | **161** | 114 | 152 | **148** | 118 |
| Natural Gas (Mcf/d) | **13,999** | 13,380 | 12,435 | **12,703** | 13,110 |
| Total (boe/d) | **4,952** | 4,964 | 4,838 | **4,781** | 4,674 |
| **Total Company** | | | | | |
| Oil (bbls/d) | **5,045** | 7,473 | 6,164 | **5,991** | 6,933 |
| NGLs (bbls/d) | **410** | 383 | 535 | **446** | 384 |
| Natural Gas (Mcf/d) | **48,379** | 51,533 | 46,647 | **46,460** | 46,057 |
| Total (boe/d) | **13,518** | 16,445 | 14,474 | **14,180** | 14,993 |
| Oil & Liquids weighting | **40%** | 48% | 46% | **45%** | 49% |

## Commodity Pricing

The principal trading exchange that affects Spyglass' oil price is the US benchmark West Texas Intermediate at Cushing, Oklahoma ("WTI") spot price. The US WTI is the basis for settling of the Edmonton Par benchmark to which most of Spyglass' crude is benchmarked.

The average Q3 2014 US WTI price of $97.17 US/bbl ($105.85 CDN/bbl) compares to $105.83 US/bbl ($109.90 CDN/bbl) in Q3 2013 and $103.00 US/bbl ($112.32 CDN/bbl) in Q2 2014. The decline in CDN WTI pricing from Q3 2013 and Q2 2014 incorporates the exchange rate movement from 0.963 US/CDN in Q3 2013 to 0.917 US/CDN and 0.918 US/CDN in the second and third quarters of 2014 respectively.

Spyglass' corporate differential incorporates its portfolio of oil sold through multiple crude oil streams reflecting differentials adjusted for quality and transportation. Differentials can vary widely for all crude oil streams depending on market conditions. For Spyglass' crude oil streams, the realized prices across the quarters were $87.58 CDN/bbl in Q3 2014, compared to $97.38 CDN/bbl in Q3 2013 and $95.28 CDN/bbl in Q2 2014. As a percentage of CDN WTI the corporate differential was 17% in Q3 2014, 11% in Q3 2013 and 15% in Q2 2014.

Canadian natural gas prices remain volatile but have improved from the prior year. The Alberta daily spot natural gas price average in Q3 2014 of $4.02/Mcf is markedly improved from the $2.43/Mcf AECO daily in Q3 2013 but lower than the Q2 2014 price of $4.69/Mcf. Spyglass sells gas on a blend of both the AECO monthly and daily index. In Q3 2014, the Company sold approximately 46% on the AECO daily index, 52% on the monthly index and 2% through aggregators, resulting in a realized natural gas price of $4.25/Mcf. This compares to $2.58/Mcf received in Q3 2013 and $4.75/Mcf in Q2 2014. The heat content of Spyglass' natural gas production is slightly above the industry average used in the benchmark $/Mcf prices and therefore realized prices for Spyglass are expected to be slightly higher than the average of AECO Alberta daily and Alberta monthly benchmark prices.

Spyglass' NGL production represents approximately 3-4 percent of production mix and consists of Ethane, Butane, Propane and Condensate. Pricing of NGL's is sensitive to the specific product produced and can vary from period to period depending on the mix of NGL production. In Q3 2014, overall realized NGL price averaged $57.46/bbl or 54% of CDN$ WTI compared to $48.02/bbl or 44% of CDN$ WTI in Q3 2013 and $55.63/bbl or 50% of CDN$ WTI in Q2 2014.

The following table outlines benchmark prices compared to Spyglass' realized prices:

| **Prices and Marketing** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| **Benchmark Prices[(1)]** | | | | | |
| WTI Oil ($US/bbl) | **$ 97.17** | $ 105.83 | $ 103.00 | **$ 99.61** | $ 98.18 |
| US/CDN average exchange rate | **0.918** | 0.963 | 0.917 | **0.914** | 0.977 |
| WTI Oil ($CDN/bbl) | **105.85** | 109.90 | 112.32 | **109.01** | 100.48 |
| Edmonton Par ($/bbl) | **97.16** | 104.93 | 105.61 | **100.86** | 95.29 |
| Alberta daily spot ($/Mcf) | **4.02** | 2.43 | 4.69 | **4.80** | 3.09 |
| Alberta monthly ($/Mcf) | **$ 4.15** | $ 2.82 | $ 4.68 | **$ 4.52** | $ 3.16 |
| **Spyglass' Realized Prices** | | | | | |
| Oil ($/bbl) | **$ 87.58** | $ 97.38 | $ 95.28 | **$ 91.13** | $ 85.31 |
| NGLs ($/bbl) | **57.46** | 48.02 | 55.63 | **62.27** | 55.21 |
| Combined Oil & NGLs ($/bbl) | **85.31** | 94.98 | 92.12 | **89.13** | 83.73 |
| Natural gas ($/Mcf) | **4.25** | 2.58 | 4.75 | **4.68** | 3.17 |
| **Total ($/boe)** | **$ 49.64** | $ 53.45 | $ 57.95 | **$ 55.79** | $ 50.60 |

[(1)] Natural gas benchmark prices are from the Canadian Gas Price Reporter with the price per GJ converted to Mcf at 1.0546. Oil benchmark prices are the volume weighted average of the Net Energy and TMX indexes.

## Financial Derivative Instruments

As part of its risk management program, Spyglass has entered into financial derivative contracts for a portion of its oil and natural gas production to assist with managing the volatility of crude oil and natural gas prices. Financial derivative contracts for natural gas are generally structured to reference an AECO monthly index for settlement. This index approximates the realized price received by the Company for the physical natural gas sold. The Company's financial derivative contracts for crude oil are generally structured to reference a WTI Canadian or WTI U.S. dollar price for settlement. The settlement price for these contracts may vary significantly from the realized crude oil price received for the physical sale of the Company's crude oil, as the WTI derivative contracts do not incorporate differentials associated with the Company's multiple crude oil streams where the price received for physical volumes is adjusted for both quality and transportation. Derivative contracts for the differentials between WCS and WTI are entered into for a portion of the Company's physical crude oil sales as WCS provides a stronger correlation to the Company's realized price.

The following table summarizes financial derivatives outstanding as at September 30, 2014 and December 31, 2013 and their estimated fair value:

| **Commodity risk management contracts** | | | | | **Fair Value as at** | |
|---|---|---|---|---|---|---|
| Instrument | Period | Price | Reference | Quantity | **September 30, 2014** | December 31, 2013 |
| Crude Oil Contracts | | | | | | |
| Swap | Aug 1, 2013 - Jul 31, 2014 | $96.12 | CDN$ WTI | 250 bbl/d | **$ -** | $ (406) |
| Swap | Jan 1, 2014 - Mar 31, 2014 | $93.65 | CDN$ WTI | 1,700 bbl/d | **-** | (1,680) |
| Swap | Jan 1, 2014 - Mar 31, 2014 | $96.23 | CDN$ WTI | 500 bbl/d | **-** | (384) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | -$24.99 | CDN$ WCS (1) | 500 bbl/d | **(395)** | (320) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $92.20 | CDN$ WTI | 1,000 bbl/d | **(819)** | (3,547) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $93.25 | CDN$ WTI | 500 bbl/d | **(361)** | (1,583) |
| Swap | Feb 1, 2014 - Dec 31, 2014 | -$21.70 | CDN$ WCS (1) | 500 bbl/d | **(224)** | - |
| Swap | Apr 1, 2014 - Jun 30, 2014 | $95.27 | CDN$ WTI | 1,000 bbl/d | **-** | (745) |
| Swap | Apr 1, 2014 - Dec 31, 2014 | $98.13 | CDN$ WTI | 600 bbl/d | **(166)** | (508) |
| Swap | Apr 1, 2014 - Dec 31, 2014 | $96.90 | CDN$ WTI | 600 bbl/d | **(233)** | (688) |
| Swap | Jul 1, 2014 - Sep 30, 2014 | $94.43 | CDN$ WTI | 500 bbl/d | **-** | (305) |
| Swap | May 1, 2014 - Dec 31, 2014 | -$21.05 | CDN$ WCS (1) | 500 bbl/d | **(214)** | - |
| Swap | Oct 1, 2014 - Dec 31, 2014 | $93.75 | CDN$ WTI | 250 bbl/d | **(170)** | (121) |
| Swap | Jan 1, 2015 - Mar 31, 2015 | $96.20 | CDN$ WTI | 500 bbl/d | **(166)** | (32) |
| Swap | Jan 1, 2015 - Mar 31, 2015 | $96.50 | CDN$ WTI | 500 bbl/d | **(153)** | (19) |
| Swap | Jan 1, 2015 - Jun 30, 2015 | $98.40 | CDN$ WTI | 500 bbl/d | **(94)** | - |
| Swap | Jan 1, 2015 - Dec 31, 2015 | -$22.80 | CDN$ WCS (1) | 500 bbl/d | **(334)** | - |
| Swap | Jan 1, 2015 - Dec 31, 2015 | $101.15 | CDN$ WTI | 500 bbl/d | **407** | - |
| Swap | Apr 1, 2015 - Dec 31, 2015 | $99.10 | CDN$ WTI | 500 bbl/d | **75** | - |
| | | | | | **$ (2,847)** | $ (10,338) |
| Natural Gas Contracts | | | | | | |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.55 | CDN$ GJ | 1,500 GJ/d | **$ (76)** | $ (86) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.555 | CDN$ GJ | 5,000 GJ/d | **(230)** | (264) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.575 | CDN$ GJ | 6,250 GJ/d | **(276)** | (284) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.59 | CDN$ GJ | 5,000 GJ/d | **(215)** | (177) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.6075 | CDN$ GJ | 3,000 GJ/d | **(124)** | (87) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.64 | CDN$ GJ | 2,000 GJ/d | **(77)** | (34) |
| Swap | Jan 1, 2014 - Dec 31, 2014 | $3.71 | CDN$ GJ | 2,000 GJ/d | **(64)** | 7 |
| Swap | Jan 1, 2015 - Mar 31, 2015 | $3.7625 | CDN$ GJ | 2,000 GJ/d | **(78)** | (17) |
| Swap | Jan 1, 2015 - Mar 31, 2015 | $4.10 | CDN$ GJ | 3,000 GJ/d | **(26)** | - |
| Swap | Jan 1, 2015 - Mar 31, 2015 | $4.14 | CDN$ GJ | 2,000 GJ/d | **(10)** | - |
| Swap | Jan 1, 2015 - Jun 30, 2015 | $4.2025 | CDN$ GJ | 3,000 GJ/d | **161** | - |
| Put | Jan 1, 2014 - Dec 31, 2014 | $3.40 | CDN$ GJ | 2,000 GJ/d | **(37)** | (58) |
| | | | | | **$ (1,052)** | $ (1,000) |
| Total | | | | | **$ (3,899)** | $ (11,338) |

(1) Fixed $ WCS versus WTI

| **Interest rate risk management contract** | | | | | **Fair Value as at** | |
|---|---|---|---|---|---|---|
| Instrument | Period | Notional Amount | Reference | Fixed Interest Rate | **September 30, 2014** | December 31, 2013 |
| Swap | Jul 5, 2012 - Jul 4, 2014 | $75,000,000 | CAD-BA-CDOR | 1.145% | **$ -** | $ 22 |
| Swap | Jan 14, 2014 - Jan 14, 2016 | $75,000,000 | CAD-BA-CDOR | 1.281% | **6** | - |
| Total | | | | | **$ 6** | $ 22 |

The following table summarizes the impact on net income (loss) for the financial derivative instrument contracts throughout the periods:

| Financial Derivative Instruments | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| **(000s)** | | | | | |
| **Realized gain (loss)** | | | | | |
| Oil | **$ (3,468)** | $ (6,789) | $ (6,373) | **$ (15,162)** | $ (8,017) |
| Gas | **(947)** | 1,476 | (1,936) | **(5,094)** | 1,082 |
| Interest | **(3)** | 14 | 1 | **6** | 42 |
| Total | **$ (4,418)** | $ (5,299) | $ (8,308) | **$ (20,250)** | $ (6,893) |
| **Unrealized gain (loss)** | | | | | |
| Oil | **$ 8,949** | $ (2,502) | $ 2,666 | **$ 7,492** | $ (9,674) |
| Gas | **2,320** | (584) | 2,789 | **(52)** | 2,594 |
| Interest | **(20)** | (52) | 19 | **(17)** | (109) |
| Total | **$ 11,249** | $ (3,138) | $ 5,474 | **$ 7,423** | $ (7,189) |
| **($/boe)** | | | | | |
| **Realized gain (loss)** | | | | | |
| Oil ($/bbl) | **$ (7.47)** | $ (9.88) | $ (11.36) | **$ (9.27)** | $ (4.24) |
| Gas ($/Mcf) | **(0.21)** | 0.31 | (0.46) | **(0.40)** | 0.09 |
| Interest ($/boe) | **-** | 0.01 | - | **-** | 0.01 |
| Total ($/boe) | **$ (3.55)** | $ (3.50) | $ (6.31) | **$ (5.23)** | $ (1.68) |
| **Unrealized gain (loss)** | | | | | |
| Oil ($/bbl) | **$ 19.28** | $ (3.64) | $ 4.75 | **$ 4.58** | $ (5.11) |
| Gas ($/Mcf) | **0.52** | (0.12) | 0.66 | **-** | 0.21 |
| Interest ($/boe) | **(0.02)** | (0.03) | 0.01 | **-** | (0.03) |
| Total ($/boe) | **$ 9.05** | $ (2.07) | $ 4.16 | **$ 1.92** | $ (1.76) |

### Petroleum and Natural Gas Sales

Petroleum and natural gas sales totalled $61.7 million for Q3 2014 compared to $80.9 million for Q3 2013 and $76.3 million for Q2 2014. Oil and liquids sales decreased $25.8 million from Q3 2013 with $21.0 million attributable to lower production volumes and $4.8 million attributable to decreased realized corporate pricing. Natural gas sales were up $6.6 million in Q3 2014 compared to Q3 2013 with $7.4 million due to higher gas prices offset by $0.8 million related to lower production volumes.

Compared to Q2 2014, petroleum and natural gas sales decreased $14.6 million, with oil and liquids accounting for $13.3 million of the decrease and natural gas sales down $1.3 million. Oil and liquids sales reflect a $9.9 million decrease on account of lower pricing and a $3.4 million decrease due to decreased production. Natural gas sales were down $2.3 million as a result of lower pricing partially offset by $1.0 million attributed to increased production.

On a YTD 2014 basis, petroleum and natural gas sales have decreased $8.9 million to $216.0 million compared to $207.1 million for the same period in 2013. Oil and liquids sales decreased $10.7 million with improved pricing resulting in a $9.4 million increase offset by reduced production resulting in a decrease of $20.1 million. Natural gas sales have increased by $19.5 million with the improvement in gas prices contributing to the majority of the increase assisted by slightly higher production.

The following table outlines petroleum and natural gas sales for the periods indicated below:

| Petroleum and Natural Gas Sales (000s) | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| Oil | **$ 40,642** | $ 66,947 | $ 53,444 | **$ 149,040** | $ 161,478 |
| NGLs | **2,170** | 1,690 | 2,708 | **7,576** | 5,791 |
| Natural Gas | **18,919** | 12,222 | 20,174 | **59,358** | 39,836 |
| Total | **$ 61,731** | $ 80,859 | $ 76,326 | **$ 215,974** | $ 207,105 |

## Royalties

Royalty payments are made by producers of oil and natural gas to the owners of the mineral rights on leases that include provincial governments (Crown) and freehold landowners as well as to other third parties by way of contractual overriding royalties. Royalties are sensitive to both pricing and production and will fluctuate accordingly.

Spyglass' Q3 2014 overall effective royalty rate for all products as a percentage of petroleum and natural gas sales was 17.5%, consistent with the 17.7% in Q2 2014 and lower than the 21.5% in Q3 2013. The majority of the percentage decrease in royalties compared to Q3 2013 is due to revenue from natural gas comprising a larger portion of petroleum and natural gas sales, with natural gas royalties, in general, having lower royalty percentages than oil. Additionally, lower oil prices resulted in reduced oil royalty percentages, which are paid on a sliding scale.

Gross overriding and other royalties averaged approximately 3-4% of petroleum and natural gas sales for Q3 2014, consistent with Q3 2013 and Q2 2014. As a percentage of total royalties paid, gross overriding royalties for Q3 2014 accounted for 20% of the total compared to 14% in Q3 2013 and 15% in Q2 2014.

For YTD 2014, the effective royalty rate was 17.8% compared to 20.7% for the same period in 2013. The decrease is mainly due to revenue from natural gas comprising a larger portion of total sales which, in general, pay at a lower royalty percentage.

The following tables outline royalties by type:

| Royalties by Type (000s) | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| Crown | **$ 8,665** | $ 14,869 | $ 11,558 | **$ 31,498** | $ 36,636 |
| Gross overriding and other | **2,135** | 2,485 | 1,971 | **6,856** | 6,316 |
| | **$ 10,800** | $ 17,354 | $ 13,529 | **$ 38,354** | $ 42,952 |
| $/boe | **$ 8.68** | $ 11.47 | $ 10.27 | **$ 9.91** | $ 10.49 |
| % of Petroleum & natural gas sales | **17.5%** | 21.5% | 17.7% | **17.8%** | 20.7% |

## Operating Expenses

Operating expenses totalled $24.2 million or $19.49/boe for Q3 2014 compared to $27.0 million or $17.86/boe in Q3 2013 and $24.1 million or $18.27/boe in Q2 2014.

Operating costs for Q3 2014 were lower than Q3 2013 by $2.8 million on an absolute dollar basis, but higher by $1.63 on a per boe basis due primarily to the fixed component of operating expenses, as well as reduced production as a result of non-core property dispositions that closed in the quarter and the Dixonville pipeline incidents which reduced quarterly average production by approximately 1,770 boe/d. Operating costs for the quarter were within the Company's previous guidance of $19.00/boe to $20.00/boe. Q3 2014 operating costs were slightly higher than the $24.1 million or $18.27/boe incurred in Q2 2014 due partially to higher power costs in the quarter which peaked at $122.54 per megawatt hour ("MWH") in July 2014, compared to averages of between $30 to $55 per MWH in Q2 2014. Operating expense per boe was $1.22 higher in Q3 2014 than in Q2 2014 due to reduced production as a result of non-core property dispositions closing in the quarter and reduced production at Dixonville due to the pipeline incidents.

On a YTD 2014 basis, operating expenses were $77.5 million or $20.03/boe compared to $78.1 million or $19.09/boe for the same period in 2013. Operating costs for the first quarter of 2013 reflect only the Pace legacy assets. Operating costs have continued to trend downward YTD on a boe basis from highs in Q1 2014 when the Company executed the majority of its annual maintenance program for the year. Management anticipates that 2014 operating costs will average approximately $20.00 per boe.

The following table summarizes the Company's operating expenses:

| **Operating Expenses** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| (000s) | **$ 24,242** | $ 27,012 | $ 24,060 | **$ 77,537** | $ 78,135 |
| $/boe | **$ 19.49** | $ 17.86 | $ 18.27 | **$ 20.03** | $ 19.09 |

## Transportation Expenses

Transportation expenses totalled $2.3 million or $1.87/boe for Q3 2014 compared to $3.1 million or $2.03/boe for Q3 2013 and $2.8 million or $2.10/boe in Q2 2014. Transportation costs are incurred for clean oil trucking and for oil and gas pipeline tariffs where tolls are paid directly to third parties.

Clean oil trucking charges relate primarily to the Dixonville property since the majority of the Company's other properties are tied into sales pipelines, although the Company does incur some clean oil trucking charges in Matziwin in its South core area. Total oil transportation charges per boe in the current quarter decreased from Q3 2013 and Q2 2014 due to decreased production at Dixonville.

Spyglass pays tariffs on its natural gas volumes transported through third party pipelines and has entered into firm transportation commitments for a portion of those volumes; refer to "contractual obligations" section.

On a YTD 2014 basis, transportation expenses totaled $8.2 million or $2.11/boe, slightly lower than the same period in the prior year on both an absolute dollar and a per boe basis.

The following table details the Company's transportation expenses:

| **Transportation Expenses** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| **(000s)** | | | | | |
| Oil | **$ 1,310** | $ 2,037 | $ 1,874 | **$ 5,308** | $ 5,999 |
| Gas | **1,012** | 1,032 | 890 | **2,863** | 2,864 |
| Total | **$ 2,322** | $ 3,069 | $ 2,764 | **$ 8,171** | $ 8,863 |
| Oil ($/bbl) | **$ 2.82** | $ 2.96 | $ 3.34 | **$ 3.25** | $ 3.17 |
| Gas ($/Mcf) | **0.23** | 0.22 | 0.21 | **0.23** | 0.23 |
| Total ($/boe) | **$ 1.87** | $ 2.03 | $ 2.10 | **$ 2.11** | $ 2.17 |

## Finance Expenses

Interest expenses include interest on Spyglass' operating line of credit. Interest expenses totalled $4.0 million in Q3 2014, higher than the $3.6 million interest expense in Q3 2013 and lower than the $4.3 million in Q2 2014. The increase in interest expense from Q3 2013 is the result of higher average borrowings throughout the quarter while the decrease from Q2 2014 is the result of closing $42.8 million of non-core property dispositions in the quarter. On a YTD 2014 basis, interest expense at $16.3 million was higher than the $13.2 million incurred YTD 2013 which reflects additional obligations assumed as a result of the Arrangement completed on March 28, 2013.

The effective interest rate for Q3 2014 was 5.4%, compared to 4.7% in Q3 2013 and 5.1% in Q2 2014.

Accretion expense on decommissioning liabilities was $1.5 million in Q3 2014, consistent with Q3 2013 and Q2 2014.

The following table details the Company's finance expenses:

| Finance Expenses | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| **($/boe)** | | | | | |
| Interest | **$ 3.25** | $ 2.39 | $ 3.25 | **$ 3.09** | $ 2.30 |
| Accretion | **1.17** | 0.99 | 1.10 | **1.12** | 0.93 |
| Total ($/boe) | **$ 4.42** | $ 3.38 | $ 4.35 | **$ 4.21** | $ 3.23 |

## Transaction Costs

The YTD 2013 results include $13.5 million of transaction costs incurred in Q1 2013 related to the Arrangement. Costs include amounts for financial advisors, legal, other professional fees and change of control settlements.

## General and Administration Expenses

Q3 2014 general and administration ("G&A") expenses of $4.4 million remained relatively consistent compared to $4.2 million in Q3 2013 and $4.4 million in Q2 2014. Current quarter G&A expenses incorporate reorganization costs of $1.1 million associated with staff reductions related to the sale of non-core assets.

On a YTD 2014 basis, G&A of $13.3 million compares to $13.2 million for the same period in 2013. In 2013, G&A costs reflected a first quarter of Pace as a stand-alone entity followed by a quarter significantly burdened by transition costs associated with the Arrangement. In 2014, G&A expenses reflect costs associated with reorganization expenditures.

The largest portion of G&A is comprised of salaries and benefits and, as such, future G&A will depend on staff levels along with reorganization costs and changes to salaries and bonus incentives. The Q3 2014 G&A expenses include $1.1 million of non-recurring reorganization costs and as a result Q4 2014 G&A costs are expected to decrease on an absolute dollar and per boe basis. G&A expense for 2014 is expected to be lower than 2013 on an absolute dollar basis but the anticipated decrease in year over year daily production will result in a per boe amount of approximately $3.25/boe.

The following table summarizes the Company's G&A expenses:

| General and Administration Expenses | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| (000s) | **$ 4,395** | $ 4,185 | $ 4,408 | **$ 13,267** | $ 13,007 |
| $/boe | **$ 3.53** | $ 2.77 | $ 3.35 | **$ 3.43** | $ 3.18 |

## Long-term Incentive Plan

The Company's long-term incentive plan ("LTIP") for employees and management includes a combination of two types of share based awards depending on roles and responsibilities within the organization: restricted share units ("RSUs") and performance share units ("PSUs"). RSUs vest evenly over a three year period. PSUs vest three years from the date of grants and the awards granted are subject to a multiplier ranging from 0 to 2 based on the performance of Spyglass on a total return basis compared to a selected peer group. The Company also grants director restricted share units ("DRSU") to non-management directors of the organization. DRSUs vest three years from the date of grant. RSUs, PSUs and DRSUs are to be settled in cash, based on the share price at the time of vesting. The number of share equivalent units at the time of vesting increases commensurately with each dividend declared by the Company after the grant date. During the nine months ended September 30, 2014, the Company granted an additional 1,691,711 RSUs, 854,366 PSUs and 218,618 DRSUs. As at September 30, 2014, incorporating the increase in units commensurate with each dividend declared by the Company, as well as forfeitures and settlements in the period, 2,401,573 RSUs, 1,971,270 PSUs and 396,136 DRSUs were outstanding.

The Company accounts for its LTIP using the fair value method, which includes revaluing to market value at the end of each period. Under this method, a compensation expense is charged over the vesting period. As such, LTIP expense fluctuates with the number of RSUs, PSUs and DRSUs outstanding and share prices at the end of the period.

The following table summarizes the Company's LTIP expense:

| **Long-term Incentive Plan Expense** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| (000s) | **$ 244** | $ 570 | $ 711 | **$ 1,442** | $ 1,441 |
| $/boe | **$ 0.20** | $ 0.38 | $ 0.54 | **$ 0.37** | $ 0.35 |

## Depletion, Depreciation and Impairments

For Q3 2014, depletion, depreciation and impairments ("D&D") was $30.1 million compared to $21.4 million for Q3 2013 and $23.9 million for Q2 2014.

The Q3 2014 D&D rate before impairment of $15.21/boe was lower than the rate of $18.11/boe in Q2 2014 mostly due to the timing of expired lands, with $0.92/boe expiring in Q3 2014 versus $3.53/boe in Q2 2014. Removing the impact of expired lands, the pre-impairment D&D rate for the quarter was comparable to Q2 2014. The pre-impairment D&D rates are subject to change based on reserve updates, the timing of land expiries, depreciation of certain workover projects, and changes in production by area.

The Q3 2014 impairment charge of $11.2 million relates to the write down of exploration and evaluation assets in the North Oil cash generating unit to fair value as a result of changes in management's future development plans. The carrying value of impaired assets could be increased in future periods should development plans change. The YTD 2014 D&D impairment charge also includes a write down required on assets classified as held for sale at March 31, 2014 to fair value. These assets were held in the Peace River Arch CGU and were sold to a third party in the second quarter.

The components of D&D are as follows:

| **Depletion, depreciation and impairments** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| **(000s)** | | | | | |
| Depletion & depreciation | **$ 18,914** | $ 21,378 | $ 23,858 | **$ 61,962** | $ 55,506 |
| Impairment | **11,152** | - | - | **13,470** | - |
| Total | **$ 30,066** | $ 21,378 | $ 23,858 | **$ 75,432** | $ 55,506 |
| | | | | | |
| **($/boe)** | | | | | |
| Depletion & depreciation | **$ 15.21** | $ 14.13 | $ 18.11 | **$ 16.01** | $ 13.56 |
| Impairment | **8.97** | - | - | **3.48** | - |
| Total | **$ 24.18** | $ 14.13 | $ 18.11 | **$ 19.49** | $ 13.56 |

## Environmental Liabilities, Insurance Receivable and Dixonville Pipeline Incidents

*Dixonville*

On April 30 and May 1, 2014, Spyglass responded to two pipeline leaks in its operations at Dixonville. Containment and cleanup operations commenced within hours of the pipelines being shutoff. Both incidents fall within the Company's insurance coverage subject to a $0.5 million deductible per incident. As part of the review by the AER, Spyglass was required to shut-in the Dixonville field from May 2 until May 4, 2014. On May 4, the AER and the Company agreed that approximately 80% of the Dixonville field could be safely brought back on production, with the remainder of the field to be brought back to production in a safe and appropriate manner. The Company has chosen to sustain clean-up and remediation costs for one of the incidents which are estimated to be $0.5 million and has filed for insurance coverage for the clean-up and remediation costs for the second incident which are estimated to total $4.5 million. As of September 30, 2014, $2.8 million has been spent on cleanup costs with a further $0.5 million recorded in accrued liabilities for work performed to September 30, 2014 and $1.7 million accrued in other liabilities for future costs expected to be incurred.

On June 26, 2014, a third incident occurred on an emulsion pipeline in Dixonville, with less than 10 cubic meters of fluid released resulting in minor cleanup costs, below the Company's insurance deductible. Subsequent to this incident, the AER issued a shut-in order for the Dixonville oil field pending pipeline inspections. Throughout the third quarter and to date, Spyglass has undertaken an extensive pipeline remediation project that involves pulling tight liners through existing pipe and in limited circumstances replacing sections of the pipeline. As this work is completed the Dixonville field is being returned to production in stages. As of the date of the MD&A, 70% or 2,100 boe/d was back on production.

The Company estimates that the impact of the Dixonville pipeline incidents decreased operating cash flow and net income by approximately $8.9 million and $6.6 million for the three months ended September 30, 2014 respectively, and $11.5 million and $8.6 million for the nine months ended September 30, 2014 when compared to 2013 performance. This factors in the impact of the insurance deductible, operating costs related to the cleanup, reduced revenues, royalties, operating expenses and deferred income taxes against 2013 performance for the area. For the year ended December 31, 2014, the incidents are anticipated to decrease operating cash flow and net income by approximately $13.5 million and $10.1 million respectively against 2013 performance. Capital expenditures associated with the remediation project are expected to total approximately $11.9 million, with $11.0 million of this incurred in 2014.

*Rainbow*

On May 19, 2012, Spyglass was made aware of a breach in an above-ground section of wellhead piping that resulted in a temporary release of an estimated 800 cubic meters of oil in the Rainbow Lake area of Northern Alberta. This incident falls within the Company's insurance coverage and $20.5 million of insurance proceeds were received to September 30, 2014. The Company has accrued $3.0 million in other liabilities for future costs expected to be incurred.

## Other Income

Q3 2014 other income of $2.9 million consists primarily of gains on the disposition of non-core producing properties. The remaining $0.3 million relates to seismic data sales completed in the quarter. On a YTD 2014 basis, the Company has closed $53.0 million in non-core asset dispositions net of acquisitions, resulting in $7.9 million of gains on dispositions. Additionally, YTD 2014 other income includes a gain on sale of investments of $0.2 million. The YTD 2013 other income includes $81.9 million in estimated gains recognized as a result of the fair value of assets acquired under the Arrangement exceeding the consideration paid, which was increased to $84.2 million in Q4 2013 as the purchase price allocation was finalized.

The following is a breakdown of other income:

| Other Income | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| **(000s)** | | | | | |
| Cash other income | **$ 295** | $ 1,227 | $ 62 | **$ 430** | $ 1,447 |
| Non-cash other income | **2,595** | 1,850 | 4,369 | **8,082** | 83,716 |
| Total | **$ 2,890** | $ 3,077 | $ 4,431 | **$ 8,512** | $ 85,163 |
| | | | | | |
| **($/boe)** | | | | | |
| Cash other income | **$ 0.24** | $ 0.81 | $ 0.05 | **$ 0.11** | $ 0.35 |
| Non-cash other income | **2.09** | 1.22 | 3.32 | **2.09** | 20.45 |
| Total | **$ 2.33** | $ 2.03 | $ 3.37 | **$ 2.20** | $ 20.80 |

## Deferred Taxes

Spyglass recorded a deferred tax recovery of $1.9 million in Q3 2014 compared to an expense of $2.1 million in Q2 2014 and a recovery of $1.8 million in Q3 2013. The difference between the Q3 2014 expected rate of 25.0% and the effective rate relates primarily to permanent differences as well as deductions for the spending associated with decommission expenditures.

## Funds from Operations and Net Income (Loss)

For Q3 2014, funds from operations totalled $11.9 million and $0.09 per basic and diluted share compared to $21.5 million and $0.17 per basic and diluted share in Q3 2013 and $19.0 million or $0.15 per basic and diluted share in Q2 2014.

Compared to Q3 2013, funds from operations in Q3 2014 decreased $9.6 million. Operating netbacks at $19.60 per boe were $2.49 per boe lower than $22.09 per boe in Q3 2013 with a lower percentage of production weighted toward crude oil and liquids. This combined with lower crude oil and natural gas prices drove a $4.7 million decrease in field cash flow as well as lower production volumes resulting in a further decrease of $14.4 million. These reductions were offset by lower royalties and operating expenses of $6.6 million and $2.9 million respectively.

Compared to Q2 2014, funds from operations decreased $7.1 million in Q3 2014 due mostly to lower production volumes, a lower weighting to crude oil and liquids, as well as lower crude oil and natural gas prices than the prior quarter to total to a $14.6 million decrease in revenues. This was offset by lower royalties of $2.7 million and lower losses on financial derivative instruments of $3.9 million.

For Q3 2014, the Company had a net loss of $4.2 million or $0.03 per basic and diluted share compared to a net loss of $1.4 million in Q3 2013 or $0.01 per basic and diluted share and a net income of $0.8 million in Q2 2014 or $0.01 per basic and diluted share. Compared to Q3 2013, the increase in net loss is primarily due to impairments recorded in Q3 2014 and reduced revenues in the quarter, partially offset by unrealized gains on financial derivative instruments in Q3 2014 versus unrealized losses in Q3 2013. The net loss of $4.2 million in Q3 2014 compared to the net income of $0.8 million in Q2 2014 was largely driven by impairment charges and reduced revenue in the current quarter, offset by higher unrealized hedging gains in Q3 2014 and a deferred tax recovery in Q3 2014 versus a deferred tax expense in Q2 2014.

The following table summarizes the net income on a boe basis for the periods indicated:

| **($/boe)** | **Q3 2014** | Q3 2013 | Q2 2014 | **YTD 2014** | YTD 2013 |
|---|---|---|---|---|---|
| Sales price | **$ 49.64** | $ 53.45 | $ 57.95 | **$ 55.79** | $ 50.60 |
| Royalties | **(8.68)** | (11.47) | (10.27) | **(9.91)** | (10.49) |
| Operating expenses | **(19.49)** | (17.86) | (18.27) | **(20.03)** | (19.09) |
| Transportation expenses | **(1.87)** | (2.03) | (2.10) | **(2.11)** | (2.17) |
| **Operating netback** | **$ 19.60** | $ 22.09 | $ 27.31 | **$ 23.74** | $ 18.85 |
| Other non-cash expenses | **0.07** | - | - | **0.02** | - |
| Cash other income (expense) | **0.24** | 0.81 | 0.05 | **0.11** | 0.35 |
| Realized gain (loss) on financial derivative instruments | **(3.55)** | (3.50) | (6.31) | **(5.23)** | (1.68) |
| G&A | **(3.53)** | (2.77) | (3.35) | **(3.43)** | (3.21) |
| Interest | **(3.25)** | (2.39) | (3.25) | **(3.09)** | (2.30) |
| **Cash flow netback** | **$ 9.58** | $ 14.24 | $ 14.45 | **$ 12.12** | $ 12.01 |
| Unrealized gain (loss) on financial derivative instruments | **9.05** | (2.07) | 4.16 | **1.92** | (1.76) |
| Other non-cash expenses | **(0.07)** | - | - | **(0.02)** | - |
| Non-cash other income (expense) | **2.09** | 1.22 | 3.32 | **2.09** | 20.45 |
| Depletion, depreciation and impairment | **(24.18)** | (14.13) | (18.11) | **(19.49)** | (13.56) |
| Accretion | **(1.17)** | (0.99) | (1.10) | **(1.12)** | (0.93) |
| Transaction costs | **-** | - | - | **-** | (3.29) |
| Long-term incentive compensation | **(0.20)** | (0.38) | (0.54) | **(0.37)** | (0.32) |
| Deferred taxes | **1.54** | 1.18 | (1.56) | **0.97** | 2.10 |
| **Net income (loss)** | **$ (3.36)** | $ (0.93) | $ 0.62 | **$ (3.90)** | $ 14.70 |

The following table provides reconciliations to the change in funds from operations and net income for Q3 2014 to Q3 2013 and for Q3 2014 to Q2 2014.

| Change in Funds from Operations and Net Income (loss) (000s) | Q3 2014 to Q3 2013 | | Q3 2014 to Q2 2014 | |
|---|---|---|---|---|
| | **Funds from Operations** | Net income / (loss) | **Funds from Operations** | Net income / (loss) |
| Comparative period | **$ 21,547** | $ (1,402) | **$ 19,043** | $ 815 |
| Increase (decrease) in revenue: | | | | |
| Change in production volumes | **(14,389)** | (14,389) | **(4,254)** | (4,254) |
| Change in prices | **(4,739)** | (4,739) | **(10,341)** | (10,341) |
| Change in royalties | **6,554** | 6,554 | **2,729** | 2,729 |
| (Increase) decrease in expenses: | | | | |
| Operating | **2,859** | 2,770 | **(93)** | (182) |
| Transportation | **747** | 747 | **442** | 442 |
| Finance charges | **(416)** | (376) | **240** | 235 |
| General and administration | **(210)** | (210) | **13** | 13 |
| Long-term incentive compensation | **-** | 326 | **-** | 467 |
| Depletion, depreciation and impairment | **-** | (8,688) | **-** | (6,208) |
| Deferred tax | **-** | 138 | **-** | 3,972 |
| Transaction costs | **-** | - | **-** | - |
| Increase (decrease) in: | | | | |
| Other income | **(932)** | (187) | **233** | (1,541) |
| Gains (losses) on financial derivative instruments | **881** | 15,268 | **3,890** | 9,665 |
| **Current period** | **$ 11,902** | $ (4,188) | **$ 11,902** | $ (4,188) |

## Capital Expenditures, Acquisitions, Dispositions and Assets Held for Sale

Capital expenditures in Q3 2014 totalled $29.1 million with $15.8 million spent on drilling, completion and optimization activities, $11.6 million on facilities, pipelines, equipping and tie-ins including pipeline integrity activities in Dixonville, $1.2 million on office costs which was substantially capitalized G&A, and the remaining $0.5 million on land and seismic. The majority of the capital focused on the drilling and completion of 8 gross oil wells (8.0 net) in the Halkirk-Provost area and 2 gross oil wells (2.0 net) in Cessford, all of which are currently on production. Additionally, $6.5 million was spent in the quarter on pipeline remediation, primarily at Dixonville.

In Q3 2014, the Company closed the sale of certain non-core producing properties that were classified as assets held for sale at June 30, 2014, for proceeds of $42.8 million, net of adjustments. The net impact of the Q3 dispositions was a gain of $2.6 million that was recognized in the Consolidated Statement of Income (Loss) for the quarter.

YTD 2014 capital expenditures totalled $62.3 million with $41.4 million spent on drilling, completion and optimization activities, $15.6 million on facilities, pipelines, equipping and tie-ins of which $7.7 million related to pipeline remediation at Dixonville, $3.9 million of capitalized G&A and office related expenditures and $1.4 million on purchased seismic and land. First quarter drilling of 8 gross (4.3 net) wells were all focused on crude oil opportunities, before the improvement in forecasted natural gas prices initiated drilling a horizontal gas well in Noel (1.0 net) in the second quarter. Third quarter drilling of 10 gross (10.0 net) wells once again focused on crude oil properties in Halkirk-Provost and Cessford. The Company has also closed $55.5 million in non-core dispositions and $2.5 million of acquisitions YTD 2014 recording $7.9 million of gains on dispositions, and $2.3 million of impairment charges on reclassification of assets as held for sale.

At September 30, 2014, the Company had $1.3 million of assets held for sale with $0.1 million of associated liabilities. The assets held for sale and associated liabilities were sold in the fourth quarter for proceeds of $1.3 million.

The following table highlights the breakdown of expenditures by category for the periods indicated:

| Capital Expenditures (000s) | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| Land | **$ 61** | $ 403 | $ 406 | **$ 691** | $ 695 |
| Geological and geophysical | **428** | 456 | 184 | **723** | 1,700 |
| Drilling and completions | **15,821** | 19,226 | 12,087 | **41,429** | 30,276 |
| Facilities and equipment | **11,615** | 2,883 | 1,403 | **15,565** | 7,617 |
| Office and capitalized G&A | **1,153** | 1,591 | 1,322 | **3,919** | 4,375 |
| Capital Expenditures | **$ 29,078** | $ 24,559 | $ 15,402 | **$ 62,327** | $ 44,663 |
| Acquisitions | **-** | - | 2,520 | **2,520** | 282,093 |
| Dispositions | **(42,836)** | (10,199) | (7,344) | **(55,508)** | (10,199) |
| Total capital expenditures and acquistions net of dispostions | **$ (13,758)** | $ 14,360 | $ 10,578 | **$ 9,339** | $ 316,557 |
| Exploration and evaluation expenditures | **$ (3,607)** | $ 873 | $ 613 | **$ (2,798)** | $ 50,049 |
| Property, plant and equipment expenditures | **(10,151)** | 13,487 | 9,965 | **12,137** | 266,508 |
| Total capital expenditures and acquisitions net of dispositions | **$ (13,758)** | $ 14,360 | $ 10,578 | **$ 9,339** | $ 316,557 |

Spyglass has approximately 499,000 net acres of undeveloped land under lease at September 30, 2014.

## Equity

On March 28, 2013, pursuant to the Arrangement, 46,916,422 pre-subdivided Spyglass shares were subdivided on a basis of 1.3 to one to total 60,991,356 shares. Further, 12,117,821 shares were issued in exchange for all outstanding Charger shares and 54,967,543 shares were issued in exchange for all outstanding AvenEx shares. Outstanding shares subsequent to the Arrangement totaled 128,076,720 Spyglass shares and to date, no further shares have been issued.

The Company has no dilutive instruments outstanding.

| Share Information | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| Shares Outstanding | | | | | |
| Basic | **128,076,720** | 128,076,720 | 128,076,720 | **128,076,720** | 128,076,720 |
| Diluted | **128,076,720** | 128,076,720 | 128,076,720 | **128,076,720** | 128,076,720 |
| Weighted average shares outstanding | | | | | |
| Basic | **128,076,720** | 128,076,720 | 128,076,720 | **128,076,720** | 106,697,849 |
| Diluted | **128,076,720** | 128,076,720 | 128,076,720 | **128,076,720** | 106,697,849 |

## Dividends Declared and Payout Ratio

During Q3 2014, the Company declared dividends of $6.7 million or $0.0525 per share. The Q3 basic payout ratio, calculated as dividends declared over funds from operations, was 56% while the all-in payout ratio, calculated using dividends declared and capital expenditures (net of property dispositions) over funds from operations, was (59)% due to significant non-core property dispositions that closed in the quarter. On a 2014 YTD basis, the basic payout ratio was 51% while the all-in payout ratio was 71%. The Company manages its payout ratio on an annual basis factoring in the dividend, the annual drilling program and the completion of non-core asset dispositions. The 2014 all-in payout ratio is expected to be approximately 85% taking into account the proceeding factors including property dispositions that closed prior to September 30, 2014 and expected dispositions of assets classified as held for sale as at September 30, 2014 as disclosed in the Q3 2014 Consolidated Financial Statements.

Dividends declared per common share and outstanding for the period are as follows:

| 2014 Dividends | Declaration Date | Record Date | Payment Date | Amount Per Common Share |
|---|---|---|---|---|
| January | January 15, 2014 | January 28, 2014 | February 17, 2014 | $ 0.0225 |
| February | February 11, 2014 | February 27, 2014 | March 17, 2014 | 0.0225 |
| March | March 11, 2014 | March 27, 2014 | April 15, 2014 | 0.0225 |
| April | April 15, 2014 | April 28, 2014 | May 15, 2014 | 0.0225 |
| May | May 6, 2014 | May 28, 2014 | June 16, 2014 | 0.0225 |
| June | June 13, 2014 | June 27, 2014 | July 15, 2014 | 0.0225 |
| July | July 14, 2014 | July 27, 2014 | August 15, 2014 | 0.0225 |
| August | August 12, 2014 | August 28, 2014 | September 15, 2014 | 0.0150 |
| September | September 11, 2014 | September 26, 2014 | October 15, 2014 | 0.0150 |

On October 16, 2014, the Company declared the October 2014 dividend of $0.0150 per share, payable on November 17, 2014 to shareholders of record on October 31, 2014.

## Liquidity and Capital Resources

Spyglass is listed on the Toronto Stock Exchange trading under the symbol “SGL” and trades in the over the counter market in the United States under the symbol “SGLRF”. The following is a summary of the trading history for Q3 2014, Q3 2013, Q2 2014, YTD 2014 and YTD 2013.

| Trading History on the TSX | Q3 2014 | Q3 2013 | Q2 2014 | YTD 2014 | YTD 2013 |
|---|---|---|---|---|---|
| Trading price | | | | | |
| High | **$ 1.77** | $ 2.01 | $ 1.97 | **$ 2.14** | $ 2.71 |
| Low | **$ 1.37** | $ 1.53 | $ 1.64 | **$ 1.37** | $ 1.53 |
| Close | **$ 1.38** | $ 1.66 | $ 1.73 | **$ 1.38** | $ 1.66 |
| Volume (000's) | **16,159** | 23,514 | 22,844 | **58,792** | 51,039 |

On the over the counter market, 20.4 million shares were traded YTD in 2014 compared to 13.2 million shares YTD in 2013.

On May 5, 2014, Spyglass renewed and amended its revolving term credit facility with a syndicate of banks. On September 8, 2014 the credit facility was further amended as a result of property dispositions that occurred in the third quarter to reduce the borrowing base. The renewed and amended credit facility of $365 million provides for a $340 million revolving credit facility and a $25 million development loan. The development facility requires consent of the bank syndicate prior to being drawn. The available level of credit is subject to semi-annual review and may be adjusted for changes in reserves, commodity prices and other factors. At September 30, 2014, $267.4 million was drawn on the facility and the Company had a working capital deficit of $26.4 million (excluding current portion of financial derivative instruments and liabilities associated with assets held for sale) for net debt of $293.8 million. The Company is subject to certain non-financial covenants in its credit facility agreement. Covenants include reporting requirements, permitted dispositions, permitted financial derivatives, permitted encumbrances and other standard business operating covenants. The Company is not subject to any financial covenants. As at September 30, 2014 the Company is in compliance with all covenants. The facility is available on a revolving basis until April 28, 2015. On April 28, 2015 at the Company’s discretion, the facility is available on a non-revolving basis for a period of 366 days, at which time the facility would be due and payable. At September 30, 2014, there were $0.9 million of letters of credit outstanding.

The Company’s policy is to maintain a strong capital base to maintain financial flexibility and allow for execution of its capital investment program, provide creditor and market confidence and sustain the future development of the business.

The Company anticipates adequate liquidity to fund future working capital, dividend payments and forecasted capital expenditures for the remainder of 2014 through a combination of cash flow, property dispositions and use of its bank facility. With continued property dispositions, the Company would expect to have a borrowing base reduction under its current bank facility, however, proceeds from property dispositions would be expected to be in excess of any reduction that would occur. The Company is able to modify its capital

program in response to changes in commodity prices and cash flows. Should the Company choose to expand its capital program, actual funding alternatives will be influenced by the then current market environment and the ability to access capital on reasonable terms, balanced with the investment opportunities presented.

## Off Balance Sheet Transactions

There were no off balance sheet transactions entered into during the period, nor are there any outstanding as of the date of this MD&A.

## Contractual Obligations

The contractual obligations for which the Company is responsible are as follows:

| Contractual Obligations (000s) | Total | < 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|---|
| Long-term debt and related interest | **$ 285,450** | $ 14,440 | $ 271,010 | $ - | $ - |
| Firm transportation charges | **4,366** | 1,646 | 2,275 | 226 | 219 |
| Operating leases | **27,180** | 3,145 | 6,999 | 7,058 | 9,978 |
| Total Contractual Obligations | **$ 316,996** | $ 19,231 | $ 280,284 | $ 7,284 | $ 10,197 |

The Company enters into many contractual obligations in the course of conducting its day to day business. Material contractual obligations consist of long-term debt under its bank facility, firm transportation charges and operating lease arrangements.

The Company estimates it will incur costs of approximately $367.4 million on an undiscounted basis, excluding obligations associated with assets classified as held for sale, to settle its decommissioning liabilities to abandon and reclaim petroleum and natural gas assets including well sites, gathering systems and processing facilities. The present value of these expected costs is $83.3 million and has been recorded on the Company's balance sheet as at September 30, 2014. These costs will be incurred over the operating lives of the assets with the majority being at or after the end of production. The Company may enter into farm-in agreements where it commits to capital expenditures to earn and retain lands. These are considered routine in nature and form part of the normal course of operations for active oil and gas companies and are not included in the table above.

The Company is currently undergoing tax reviews related to issuance of flow through shares and has accrued a provision for reassessments which it is currently reviewing.

## Financial Instruments

Financial instruments comprise accounts receivable, financial derivative instruments, investments, accounts payable and accrued liabilities, dividends payable, long-term incentive plan liability and long-term debt. The fair values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, dividends payable approximate their carrying amounts due to their short-term maturities. Spyglass' financial derivative instruments and long-term incentive plan liability have been recorded at their fair value.

The Company's long-term debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value. The Company is exposed to credit, liquidity and market risk from its use of financial instruments. A description of these risks has been included in the Company's year-end audited consolidated financial statements for December 31, 2013.

## Disclosure Controls and Procedures

Disclosure controls and procedures are designed to ensure that information required to be disclosed by Spyglass is accumulated and communicated to management as appropriate to allow timely disclosures. Spyglass' Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the interim filings, that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to Spyglass is made known to them by Spyglass employees.

## Internal Control over Financial Reporting ("ICFR")

Spyglass' Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance on the reliability of Spyglass' financial reporting and preparation of financial statements for external purposes in accordance with GAAP. The control framework to design Spyglass' ICFR is the Internal Control-Integrated Framework (COSO Framework) (1992) published by the Committee of Sponsoring Organizations of the Treadway Commission. As at September 30, 2014 Spyglass' Chief Executive Officer and Chief Financial Officer have evaluated, or caused to be evaluated under their supervision, the design of the Company's internal controls over financial reporting and have concluded that these controls are designed properly.

There were no changes in the Company's internal controls during Q3 2014 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that while Spyglass' Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure and internal control procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure and internal control procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

## Application of Critical Accounting Estimates

The significant accounting policies used by Spyglass are disclosed in the Company's year-end audited consolidated financial statements for the years ended December 31, 2013 and 2012.

## Financial Reporting Update

Pronouncements and amendments for annual periods beginning on or after January 1, 2014 are disclosed in the Company's year end audited consolidated financial statements for the year ended December 31, 2013. Adopting these standards is not expected to impact the consolidated financial statements.

## Risk Factors

There are a number of risk factors facing companies that participate in the Canadian oil and gas industry. A summary of certain risk factors relating to our business are disclosed below, a more exhaustive list is provided in the Risk Factors Section of our 2013 Annual Information Form filed on SEDAR at www.sedar.com.

## Selected Quarterly Information

| Financial (000s, except per share amounts) | 2014 Q3 | 2014 Q2 | 2014 Q1 | 2013 Q4 | 2013 Q3 | 2013 Q2 | 2013 Q1 | 2012 Q4 |
|---|---|---|---|---|---|---|---|---|
| Petroleum and natural gas sales | **$ 61,731** | $ 76,326 | $ 77,917 | $ 65,909 | $ 80,859 | $ 76,405 | $ 49,841 | $ 49,475 |
| Cash flow from (used in) operations | **8,398** | 27,470 | 10,342 | 9,360 | 14,046 | 1,329 | (3,174) | 28,861 |
| Funds from operations | **11,902** | 19,043 | 16,026 | 11,426 | 21,547 | 20,558 | 7,053 | 13,631 |
| Per share- Basic | **0.09** | 0.15 | 0.13 | 0.09 | 0.17 | 0.16 | 0.11 | 0.22 |
| Per share- Diluted | **0.09** | 0.15 | 0.13 | 0.09 | 0.17 | 0.16 | 0.11 | 0.22 |
| Net income (loss) | **$ (4,188)** | $ 815 | $ (11,697) | $ (16,866) | $ (1,402) | $ 246 | $ 61,353 | $ (86,565) |
| Per share- Basic | **(0.03)** | 0.01 | (0.09) | (0.13) | (0.01) | 0.00 | 0.97 | (1.42) |
| Per share- Diluted | **(0.03)** | 0.01 | (0.09) | (0.13) | (0.01) | 0.00 | 0.97 | (1.42) |
| Capital expenditures | **$ 29,078** | $ 15,402 | $ 17,847 | $ 14,991 | $ 24,559 | $ 8,284 | $ 11,820 | $ 14,924 |
| Corporate acquisitions | **-** | - | - | - | - | - | 150,271 | - |
| Property acquistions | **-** | 2,520 | - | - | - | - | - | - |
| Dispositions | **(42,836)** | (7,344) | (5,328) | (12,515) | (10,199) | - | - | - |
| Total capital expenditures and acquisitions net of dispositions | **(13,758)** | 10,578 | 12,519 | 2,476 | 14,360 | 8,284 | 162,091 | 14,924 |
| Long term debt | **267,400** | 290,900 | 294,900 | 287,000 | 277,000 | 280,400 | 271,700 | 199,810 |
| Net debt | **293,762** | 270,828 | 307,150 | 300,508 | 291,997 | 296,853 | 300,253 | 215,817 |
| Total assets | **833,942** | 881,033 | 897,155 | 892,328 | 921,752 | 930,843 | 944,625 | 581,521 |
| Dividends Declared | **6,724** | 8,645 | 8,645 | 8,645 | 8,645 | 8,644 | - | - |
| Per share- Basic | **0.0525** | 0.0675 | 0.0675 | 0.0675 | 0.0675 | 0.0675 | - | - |
| Basic Payout Ratio | **56%** | 45% | 54% | 76% | 40% | 42% | - | - |
| All-in Payout Ratio | **-59%** | 101% | 132% | 97% | 107% | 82% | - | - |
| Shares outstanding (000s) | | | | | | | | |
| Basic | **128,077** | 128,077 | 128,077 | 128,077 | 128,077 | 128,077 | 128,077 | 60,991 |
| Diluted | **128,077** | 128,077 | 128,077 | 128,077 | 128,077 | 128,077 | 128,077 | 65,209 |
| **Operations** | | | | | | | | |
| Average daily production | | | | | | | | |
| Oil (bbls/d) | **5,045** | 6,164 | 6,784 | 7,198 | 7,473 | 7,434 | 5,876 | 5,657 |
| NGLs (bbls/d) | **410** | 535 | 391 | 647 | 383 | 490 | 279 | 285 |
| Natural gas (Mcf/d) | **48,379** | 46,647 | 44,312 | 48,164 | 51,533 | 50,626 | 35,840 | 35,804 |
| Combined (boe/d) | **13,518** | 14,474 | 14,560 | 15,873 | 16,445 | 16,362 | 12,128 | 11,909 |
| Operating netback ($/boe) | **$ 19.60** | $ 27.31 | $ 24.10 | $ 15.09 | $ 22.09 | $ 20.81 | $ 11.67 | $ 16.01 |

In Q1 2013, the Company completed the Arrangement and acquired AvenEx and Charger for consideration of $150.3 million, which resulted in a gain on acquisition of $84.2 million. In 2013, the Company drilled 16 gross (12.9 net) wells, and has drilled 19 gross (15.3 net) wells year to date in 2014.

Production averaged 13,518 in Q3 2014, lower than Q2 2014 production of 14,474 due largely to property dispositions which closed in the third quarter as well as shut-ins in Dixonville. This is lower than 2013's annual production average of 15,215 boe/d but higher than the 12,295 boe/d produced in the second half of 2012, reflecting the completion of the Arrangement late in Q1 2013. Commodity prices have been volatile over the previous eight trailing quarters which led to an impairment loss in Q4 2012, which contributed to a net loss of $86.6 million in the quarter.

## Additional Information

Additional information relating to Spyglass is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Spyglass Resources Corp., 1700, 250- 2nd Street SW, Calgary, Alberta T2P 0C1 or by email to **ir@spyglassresources.com** or by accessing the website at www.spyglassresources.com.