Q2 2015 MANAGEMENT'S DISCUSSION AND ANALYSIS

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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 six months ended June 30, 2015 and 2014 and the audited consolidated financial statements, related notes and Management's Discussion and Analysis for the years ended December 31, 2014 and 2013. This MD&A is dated as of August 11, 2015.

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 2014 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

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 six months ended June 30, 2015 ("YTD 2015") to the six months ended June 30, 2014 ("YTD 2014") and the three months ended June 30, 2015 ("Q2 2015") to the three months ended June 30, 2014 ("Q2 2014") and the three months ended March 31, 2015 ("Q1 2015").

Outlook

Drastically lower commodity prices continue to present a challenging business environment for the Company as 2015 progresses. Spyglass has prudently managed costs through reductions in staffing levels, renegotiating contract rates with business partners, temporary salary reductions and running a minimal capital program.

Management anticipates that the 2015 capital program will be $11 million, an increase from the previously disclosed $8 million, primarily focused on maintenance capital expenditures. The capital program coupled with the Company's relatively low 21 percent decline rate is expected to result in average production of approximately 9,000 boe/d for the year.

Spyglass announced a revised credit facility on June 30, 2015, resulting in the classification of the Company's bank debt as a current liability. As such, the Company continues to include a note on going concern uncertainty in its financial statements. Spyglass continues to meet all of its obligations with respect to ongoing operations.

In an effort to further reduce debt, Spyglass intends to come to market later this year with a broad disposition package incorporating both core and non-core assets. Management's attention remains on managing the resources of the Company through a difficult commodity price environment, reviewing recapitalization opportunities and ongoing property dispositions.

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 and working capital deficit 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. Working capital (deficit) equals current assets less current liabilities. Net debt equals bank debt and working capital (deficit) excluding the current portion of financial derivative instruments and liabilities associated with assets held for sale. 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:

($000s)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Cash flow from operating activities	**$ 6,760**	$ 27,470	$ 9,754	**$ 16,514**	$ 37,812
Decommissioning expenditures	**370**	729	1,092	**1,462**	3,100
Change in non-cash working capital	**4,293**	(9,156)	(6,008)	**(1,715)**	(5,843)
Funds from operations	**$ 11,423**	$ 19,043	$ 4,838	**$ 16,261**	$ 35,069

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 Q2 2015 averaged 9,849 boe/d compared to 14,474 in Q2 2014 and 11,058 in Q1 2015.

Production in Q2 2015 was lower than Q2 2014 as a result of property dispositions throughout 2014, the most significant of which was the 50% working interest disposition of the Dixonville property located in the North core area, effective January 1, 2015, which reduced Q2 2015 production by approximately 1,150 boe/d. Despite significant dispositions in 2014 and a reduced capital program, the Company was able to maintain production of just over 9,800 boe/d in Q2 2015 incorporating additions from the 2014 drilling program, offset by natural production declines and production outages for wells not brought back on stream given longer payback periods in the current commodity price environment.

Declines in production in Q2 2015 as compared to Q1 2015 reflect natural production declines as well as shut-in of uneconomic wells in the North core area that occurred late in the second quarter, which reduced Q2 2015 production by approximately 100 boe/d. The Company continues to counterbalance these impacts with targeted maintenance capital to assist in managing production declines. At Herronton in the South core area one gross (0.1 net) non-operated oil well was drilled in Q1 2015 that came on production in the current quarter, however, the impact on production was minor. The Company closed property dispositions in the North core area in late Q2 2015. The dispositions and shut-ins had a minimal impact on Q2 2015 production due to their timing, however they are expected to reduce Q3 2015 production by approximately 400 boe/d.

Oil and liquids production in Q2 2015 represented 41% of total production at 4,084 bbls/d compared to 6,699 bbls/d or 46% in Q2 2014 and 4,404 bbls/d or 40% in Q1 2015. On a YTD basis, the oil and liquids weighting decreased from 48% YTD 2014 to 41% YTD 2015. The majority of the decrease in the oil and liquids weighting when comparing Q2 2015 to Q2 2014 and YTD 2015 to YTD 2014 is due to the Dixonville disposition, which was heavily weighted to oil and liquids. The oil and liquids weighting for Q2 2015 is comparable to the weighting for Q1 2015.

On an YTD basis, YTD 2015 production was 10,451 boe/d compared to YTD 2014 of 14,516 boe/d. The decrease incorporates $163.9 million of property dispositions net of acquisitions throughout 2014 as well as by natural declines and the shut-in of uneconomic wells, partially offset by additions from the 2014 drilling program.

For 2015, incorporating the Company's low decline rate and a capital budget of $11 million, which is flexible to changes in commodity pricing, production is anticipated to average approximately 9,000 boe/d.

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

Production	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Oil (bbls/d)	**3,809**	6,164	4,112	**3,960**	6,472
NGLs (bbls/d)	**275**	535	292	**284**	464
Natural Gas (Mcf/d)	**34,589**	46,647	39,923	**37,241**	45,486
Total (boe/d)	**9,849**	14,474	11,058	**10,451**	14,516
Oil & Liquids weighting	**41%**	46%	40%	**41%**	48%

The following table sets out production volumes by core area:

	Q2 2015	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
North					
Oil (bbls/d)	**1,531**	2,949	1,598	**1,565**	3,335
NGLs (bbls/d)	**97**	255	100	**98**	216
Natural Gas (Mcf/d)	**19,280**	29,295	23,437	**21,346**	28,713
Total (boe/d)	**4,841**	8,087	5,604	**5,221**	8,337
Central					
Oil (bbls/d)	**411**	601	515	**462**	591
NGLs (bbls/d)	**66**	128	77	**71**	106
Natural Gas (Mcf/d)	**3,985**	4,917	4,266	**4,125**	4,729
Total (boe/d)	**1,142**	1,549	1,303	**1,220**	1,485
South					
Oil (bbls/d)	**1,867**	2,614	1,999	**1,933**	2,546
NGLs (bbls/d)	**112**	152	115	**115**	142
Natural Gas (Mcf/d)	**11,324**	12,435	12,220	**11,770**	12,044
Total (boe/d)	**3,866**	4,838	4,151	**4,010**	4,694
Total Company					
Oil (bbls/d)	**3,809**	6,164	4,112	**3,960**	6,472
NGLs (bbls/d)	**275**	535	292	**284**	464
Natural Gas (Mcf/d)	**34,589**	46,647	39,923	**37,241**	45,486
Total (boe/d)	**9,849**	14,474	11,058	**10,451**	14,516
Oil & Liquids weighting	**41%**	46%	40%	**41%**	48%

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 Q2 2015 US WTI price of $57.94 US/bbl ($71.23 CDN/bbl) was drastically lower than the $103.00 US/bbl ($112.32 CDN/bbl) averaged in Q2 2014 but higher than the $48.64 US/bbl ($60.37 CDN/bbl) averaged in Q1 2015 as a result of global crude oil market conditions. The decline in Q2 2015 CDN WTI pricing from Q2 2014 incorporates the favourable exchange rate movement from 0.917 US/CDN in Q2 2014 to 0.813 US/CDN in Q2 2015.

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 $58.57 CDN/bbl in Q2 2015, compared to $95.28 CDN/bbl in Q2 2014 and $44.32 CDN/bbl in Q1 2015. As a percentage of CDN WTI the corporate differential was 18% in Q2 2015, 15% in Q2 2014 and 27% in Q1 2015.

Canadian natural gas prices remain volatile, with sharp declines from the prior year. The Alberta daily spot natural gas price average in Q2 2015 of $2.65/Mcf has markedly deteriorated from the $4.69/Mcf AECO daily in Q2 2014 and has decreased slightly from the Q1 2015 price of $2.75/Mcf. Spyglass sells gas on a blend of both the AECO monthly and daily index. In Q2 2015, the Company sold approximately 52% on the AECO daily index, 46% on the monthly index and 2% through aggregators, resulting in a realized natural gas price of $2.73/Mcf. This compares to $4.75/Mcf received in Q2 2014 and $2.90/Mcf in Q1 2015. The heat content of Spyglass' natural gas production is slightly above the industry average used in the benchmark $/Mcf prices and therefore realized prices are expected to be slightly higher than the Spyglass weighted average sales for natural gas on the AECO Alberta daily and Alberta monthly indices.

Spyglass' NGL production represents approximately 3-4 percent of production mix and consists of Ethane, Propane, Butane 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 Q2 2015, overall realized NGL price averaged $39.42/bbl or 55% of CDN$ WTI compared to $55.63/bbl or 50% of CDN$ WTI in Q2 2014 and $35.22/bbl or 58% of CDN$ WTI in Q1 2015.

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

Prices and Marketing	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Benchmark Prices[1]					
WTI Oil ($US/bbl)	**$ 57.94**	$ 103.00	$ 48.64	**$ 53.32**	$ 100.85
US/CDN average exchange rate	**0.813**	0.917	0.806	**0.810**	0.912
WTI Oil ($CDN/bbl)	**71.23**	112.32	60.37	**65.86**	110.63
Edmonton Par ($/bbl)	**67.71**	105.61	51.94	**59.87**	102.74
Alberta daily spot ($/Mcf)	**2.65**	4.69	2.75	**2.70**	5.20
Alberta monthly ($/Mcf)	**$ 2.67**	$ 4.68	$ 2.95	**$ 2.81**	$ 4.72
Spyglass' Realized Prices					
Oil ($/bbl)	**$ 58.57**	$ 95.28	$ 44.32	**$ 51.21**	$ 92.54
NGLs ($/bbl)	**39.42**	55.63	35.22	**37.27**	64.43
Combined Oil & NGLs ($/bbl)	**57.28**	92.12	43.72	**50.28**	90.66
Natural gas ($/Mcf)	**2.73**	4.75	2.90	**2.82**	4.91
Total ($/boe)	**$ 33.35**	$ 57.95	$ 27.87	**$ 30.46**	$ 58.70

[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 June 30, 2015 and December 31, 2014 and their estimated fair value:

Commodity risk management contracts					**Fair Value as at**	
Instrument	Period	Price	Reference	Quantity	**June 30, 2015**	December 31, 2014
Crude Oil Contracts						
Swap	Jan 1, 2015 - Mar 31, 2015	$96.20	CDN$ WTI	500 bbl/d	**$ -**	$ 1,504
Swap	Jan 1, 2015 - Mar 31, 2015	$96.50	CDN$ WTI	500 bbl/d	**-**	1,517
Swap	Jan 1, 2015 - Jun 30, 2015	$98.40	CDN$ WTI	500 bbl/d	**-**	3,112
Swap	Jan 1, 2015 - Dec 31, 2015	-$22.80	CDN$ WCS [1]	500 bbl/d	**(648)**	(739)
Swap	Jan 1, 2015 - Dec 31, 2015	$101.15	CDN$ WTI	500 bbl/d	**2,352**	6,328
Swap	Apr 1, 2015 - Dec 31, 2015	$99.10	CDN$ WTI	500 bbl/d	**2,167**	4,342
					$ 3,871	$ 16,064
Swap	Jan 1, 2015 - Mar 31, 2015	$3.7625	CDN$ GJ	2,000 GJ/d	**$ -**	$ 174
Swap	Jan 1, 2015 - Mar 31, 2015	$4.10	CDN$ GJ	3,000 GJ/d	**-**	352
Swap	Jan 1, 2015 - Mar 31, 2015	$4.14	CDN$ GJ	2,000 GJ/d	**-**	242
Swap	Jan 1, 2015 - Jun 30, 2015	$4.20	CDN$ GJ	3,000 GJ/d	**-**	836
Swap	Apr 1, 2015 - Dec 31, 2015	$2.9400	CDN$ GJ	3,000 GJ/d	**171**	-
Swap	Apr 1, 2015 - Dec 31, 2015	$2.8450	CDN$ GJ	3,000 GJ/d	**118**	-
Swap	Jun 1, 2015 - Oct 31, 2015	$2.6600	CDN$ GJ	3,000 GJ/d	**50**	-
					$ 339	$ 1,604
Total					**$ 4,210**	$ 17,668

[1] Fixed $ WCS versus WTI

Interest rate risk management contract					**Fair Value as at**	
Instrument	Period	Notional Amount	Reference	Fixed Interest Rate	**June 30, 2015**	December 31, 2014
Swap	Jan 14, 2014 - Jan 14, 2016	$75,000,000	CAD-BA-CDOR	1.281%	**(169)**	34
Total					**$ (169)**	$ 34

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

Financial Derivative Instruments (000s)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Realized gain (loss)					
Oil	**$ 3,483**	$ (6,373)	$ 6,598	**$ 10,081**	$ (11,694)
Gas	**658**	(1,936)	1,142	**1,800**	(4,147)
Interest	**(54)**	1	(26)	**(80)**	9
Total	**$ 4,087**	$ (8,308)	$ 7,714	**$ 11,801**	$ (15,832)
Unrealized gain (loss)					
Oil	**$ (6,127)**	$ 2,666	$ (6,067)	**$ (12,194)**	$ (1,457)
Gas	**(556)**	2,789	(708)	**(1,264)**	(2,372)
Interest	**88**	19	(291)	**(203)**	3
Total	**$ (6,595)**	$ 5,474	$ (7,066)	**$ (13,661)**	$ (3,826)
Realized gain (loss)					
Oil ($/bbl)	**$ 10.05**	$ (11.36)	$ 17.83	**$ 14.07**	$ (9.98)
Gas ($/Mcf)	**0.21**	(0.46)	0.32	**0.27**	(0.50)
Interest ($/boe)	**(0.06)**	-	(0.03)	**(0.04)**	-
Total ($/boe)	**$ 4.56**	$ (6.31)	$ 7.75	**$ 6.24**	$ (6.03)
Unrealized gain (loss)					
Oil ($/bbl)	**$ (17.68)**	$ 4.75	$ (16.39)	**$ (17.01)**	$ (1.24)
Gas ($/Mcf)	**(0.18)**	0.66	(0.20)	**(0.19)**	(0.29)
Interest ($/boe)	**0.10**	0.01	(0.29)	**(0.11)**	-
Total ($/boe)	**$ (7.36)**	$ 4.16	$ (7.10)	**$ (7.22)**	$ (1.46)

Petroleum and Natural Gas Sales

Petroleum and natural gas sales totalled $29.9 million for Q2 2015 compared to $76.3 million for Q2 2014 and $27.7 million for Q1 2015. Oil and liquids sales decreased $34.9 million from Q2 2014 with $21.9 million due to lower production volumes and $13.0 million due to lower prices. Natural gas sales decreased $11.6 million in Q2 2015 compared to Q2 2014 with $6.4 million due to lower natural gas prices and by $5.2 million related to lower production volumes.

Compared to Q1 2015, petroleum and natural gas sales increased $2.2 million, with oil and liquids accounting for an increase of $4.0 million offset by a decrease in natural gas sales of $1.8 million. Oil and liquids sales reflect a $5.1 million increase on account of higher pricing and an $1.1 million decrease due to lower production. Natural gas sales were down $0.5 million as a result of lower pricing and an additional $1.3 million as a result of decreased production.

On a YTD basis, petroleum and natural gas sales have decreased by $96.6 million to $57.6 million in 2015 compared to $154.2 million for the same period in 2014. Oil and liquids sales decreased by $75.2 million with $44.2 million due to lower production volumes and $31.0 million due to lower prices. Natural gas sales have decreased by $21.4 million with $14.1 million due to decreased prices and $7.3 million due to lower production volumes.

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

Petroleum and Natural Gas Sales (000s)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Oil	**$ 20,302**	$ 53,444	$ 16,402	**$ 36,704**	$ 108,398
NGLs	**988**	2,708	925	**1,913**	5,406
Natural Gas	**8,598**	20,174	10,406	**19,004**	40,439
Total	**$ 29,888**	$ 76,326	$ 27,733	**$ 57,621**	$ 154,243

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' Q2 2015 overall effective royalty rate for all products as a percentage of petroleum and natural gas sales was 2.4%, a significant decrease from the rate of 17.7% in Q2 2014 and a decrease from 6.1% in Q1 2015. The percentage decrease in royalties compared to Q2 2014 is largely the result of significant reductions in oil and natural gas prices in the quarter, thereby reducing royalty percentages which are paid on a sliding scale for both oil and gas wells. In particular, prices have declined past floors where certain of the Company's wells have reached a nil% royalty rate. The Q2 2015 royalty rate also includes a $1.2 million credit related to the Alberta Crown 2014 natural gas cost allowance, thereby resulting in crown royalties being in a credit position for the quarter and reducing the effective total royalty rate to 2.4% in Q2 2015 compared to 6.1% in Q1 2015. Removing the impact of the reduction to 2014 Alberta crown royalties due to the gas cost allowance credits, the Q2 2015 effective royalty rate would have been 6.4%, which is comparable to the Q1 2015 rate of 6.1%.

Gross overriding and other royalties averaged approximately 3-4% of petroleum and natural gas sales for Q2 2015, consistent with Q2 2014 and Q1 2015. Gross overriding and other royalties are generally at a fixed rate versus crown royalties which are based on a sliding scale and therefore, comprise a greater percentage of royalties as prices decrease. The adjustment to Alberta crown gas cost allowance in Q2 2015 resulted in crown royalties being in a credit position for the quarter, therefore, resulting in gross overriding and other royalties account for greater than 100% of royalties in the quarter.

For YTD 2015, the effective royalty rate was 4.2% compared to 17.9% for the same period in 2014. The decrease again is largely the result of significant reductions in oil and natural gas prices in the quarter, thereby reducing royalty percentages which are paid on a sliding scale, as discussed above. Additionally, removing the impact of the 2014 natural gas cost allowance credits , the effective royalty rate for 2015 would have been 6.3%.

The following tables outline royalties by type:

Royalties by Type (000s)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Crown	**$ (202)**	$ 11,558	$ 962	**$ 760**	$ 22,833
Gross overriding and other	**909**	1,971	742	**1,651**	4,721
	$ 707	$ 13,529	$ 1,704	**$ 2,411**	$ 27,554
$/boe	**$ 0.79**	$ 10.27	$ 1.71	**$ 1.27**	$ 10.49
% of Petroleum & natural gas sales	**2.4%**	17.7%	6.1%	**4.2%**	17.9%

Operating Expenses

Operating expenses totalled $15.3 million or $17.04/boe for Q2 2015 compared to $24.1 million or $18.27/boe in Q1 2014 and $21.5 million or $21.58/boe in Q1 2015.

Operating costs for Q2 2015 were lower than Q2 2014 by $8.8 million on an absolute dollar basis and by $1.23 on a per boe basis. The reduction in absolute dollar costs is the result of property dispositions in 2014, along with cost reduction initiatives implemented by the Company in response to the decrease in commodity prices as well as favourable adjustments from prior quarters. Cost reduction initiatives include restructuring our field operations, minimizing maintenance costs to bring production back on stream given longer payback periods for funds expended, seeking cost savings from service providers and the shut-in of uneconomic wells. The reduction of operating costs on a per boe basis is less dramatic than the absolute dollar decrease due primarily to the fixed component of operating expenses and the decrease in production volumes. Q2 2015 operating costs were lower than Q1 2015 by $6.2 million on an absolute dollar basis and by $4.54 on a per boe basis. The absolute dollar and per boe decrease reflects cost reduction initiatives and reduced operating costs associated with seasonal maintenance undertaken in winter access only areas, performed in Q1 2015.

On a YTD basis, operating expenses were $36.8 million or $19.43/boe compared to $53.3 million or $20.28/boe for the same period in 2014. The decrease in the absolute dollar basis is primarily the result of property dispositions in 2014 enhanced by cost reduction initiatives. The reduction on a per boe basis is the result of cost reduction initiatives partially countered by the fixed component of operating expenses and the decrease in production volumes.

The following table summarizes the Company's operating expenses:

Operating Expenses	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
(000s)	**$ 15,277**	$ 24,060	$ 21,478	**$ 36,755**	$ 53,295
$/boe	**$ 17.04**	$ 18.27	$ 21.58	**$ 19.43**	$ 20.28

Transportation Expenses

Transportation expenses totalled $1.8 million or $1.95/boe for Q2 2015 compared to $2.8 million or $2.10/boe for Q2 2014 and $2.2 million or $2.21/boe in Q1 2015. 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 in the North core area and Matziwin in the South core area since the majority of the Company's other properties are tied into sales pipelines. Total oil transportation charges per boe in the current quarter of $2.71 reflect the disposition of a 50% working interest in Dixonville in Q4 2014 as well as the resolution of third party pipeline capacity limitations that occurred in Q1 2015 that resulted in the Company trucking oil to alternative locations. Additionally, negotiations with vendors on pricing contributed to the decrease in per boe oil trucking charges in Q2 2015 compared to Q2 2014 and Q1 2015. The decrease in oil transportation charges on a YTD basis from $4.0 million for YTD 2014 to $2.3 million YTD 2015 includes the impact of the Dixonville disposition in Q4 2014 as well as the impact of negotiations with vendors on pricing.

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.

The following table details the Company's transportation expenses:

Transportation Expenses (000s)	Q2 2015	Q2 2014	Q1 2015	YTD 2015	YTD 2014
Oil	**$ 941**	$ 1,874	$ 1,321	**$ 2,262**	$ 3,998
Gas	**811**	890	879	**1,690**	1,851
Total	**$ 1,752**	$ 2,764	$ 2,200	**$ 3,952**	$ 5,849
Oil ($/bbl)	**$ 2.71**	$ 3.34	$ 3.57	**$ 3.16**	$ 3.41
Gas ($/Mcf)	**0.26**	0.21	0.24	**0.25**	0.22
Total ($/boe)	**$ 1.95**	$ 2.10	$ 2.21	**$ 2.09**	$ 2.23

Finance Expenses

Interest expenses include interest on Spyglass' operating line of credit. Interest expenses totalled $2.4 million in Q2 2015 compared to $2.3 million in Q1 2015 reflecting minimal change in the amount drawn on the operating line of credit. The Q2 2015 interest expense is lower than the Q2 2014 interest expense of $4.3 million due to the significant reduction in average bank borrowings throughout the respective quarters. On a YTD basis, interest expense of $4.6 million for 2015 was lower than the YTD 2014 interest expense of $7.9 million. Both the 2015 and 2014 comparison quarter over quarter and YTD for interest expense reflect the decrease in amounts drawn on the operating line of credit due to significant property dispositions that occurred in the last half of 2014.

The effective interest rate for Q2 2015 was 4.9%, compared to 5.0% in Q1 2015 and 5.1% in Q2 2014. With the amendment of the credit facility completed on June 30, 2015, the Company expects its 2015 effective interest rate to average approximately 7.25%.

Accretion expense on decommissioning liabilities was $1.4 million in Q2 2015, consistent with Q1 2015 and Q2 2014.

The following table details the Company's finance expenses:

Finance Expenses	Q2 2015	Q2 2014	Q1 2015	YTD 2015	YTD 2014
(000s)					
Interest	**$ 2,381**	$ 4,276	$ 2,257	**$ 4,638**	$ 7,907
Accretion	**1,412**	1,448	1,392	**2,804**	2,868
Total	**$ 3,793**	$ 5,724	$ 3,649	**$ 7,442**	$ 10,775
($/boe)					
Interest	**$ 2.66**	$ 3.25	$ 2.27	**$ 2.45**	$ 3.01
Accretion	**1.58**	1.10	1.40	**1.48**	1.09
Total ($/boe)	**$ 4.24**	$ 4.35	$ 3.67	**$ 3.93**	$ 4.10

General and Administration Expenses

In Q2 2015 general and administration ("G&A") expenses totalled $2.6 million, lower than $4.4 million incurred in Q2 2014 and the $3.0 million incurred in Q1 2015. Decreases in G&A from Q2 2014 are primarily the result of reductions in staffing levels throughout 2014 and to date in 2015. Decreases in G&A from Q1 2015 are the result of G&A cost reduction initiatives which included further cuts in staffing, temporary salary reductions, subletting surplus office space, minimizing discretionary expenses and working with vendors to reduce costs.

On a YTD 2015 basis, G&A of $5.6 million is lower than YTD 2014 G&A of $8.9 million by $3.3 million or 37%. The significant decrease is the result of reductions in staffing levels throughout 2014 and in 2015 accompanied by other cost saving initiatives that have been implemented in response to current oil and natural gas pricing.

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. With the persistence of depressed commodity pricing, the Company has sustained cost savings initiatives previously implemented, including temporary salary reductions and will continue to pursue further cost savings initiatives. Considering the implementation of cost saving initiatives and changes in staffing related to the 2014 sale of non-core assets, the Company expects a 32% reduction in annual Cash G&A to approximately $11 million from $16.2 million in 2014.

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

General and Administration Expenses	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
(000s)	**$ 2,614**	$ 4,408	$ 2,982	**$ 5,596**	$ 8,872
$/boe	**$ 2.92**	$ 3.35	$ 3.00	**$ 2.96**	$ 3.38

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 six months ended June 30, 2015, the Company granted an additional 10,734 RSUs. As at June 30, 2015, incorporating forfeitures and settlements in the period, 2,276,961 RSUs, 1,963,504 PSUs and 348,888 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	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
(000s)	**$ (108)**	$ 711	$ 48	**$ (60)**	$ 1,198
$/boe	**$ (0.12)**	$ 0.54	$ 0.05	**$ (0.03)**	$ 0.46

Depletion, Depreciation and Impairments

For Q1 2015, depletion, depreciation and impairments ("D&D") was $103.9 million compared to $23.9 million for Q2 2014 and $13.8 million for Q1 2015.

The Q2 2015 D&D rate before impairment of $14.17/boe was lower than the rate of $18.11/boe in Q2 2014 and slightly higher than the rate of $13.87/boe in Q1 2015. The $3.94/boe decrease from the Q2 2014 D&D rate before impairment is mostly due to a decrease in the depletable asset base as a result of impairments recognized in Q4 2014 and the disposition of a 50% working interest of the Dixonville property. 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.

In Q2 2015, the Company recognized $91.2 million of impairment charges. The Company recorded $77.6 million of property, plant and equipment ("PP&E") impairments and $13.6 of exploration and evaluation ("E&E") impairments. PP&E impairments recorded in the South Oil, Central, Dixonville, North Gas and North Oil CGUs were triggered by the continued and prolonged decline in forecasted oil and natural gas prices. Additionally, significant and prolonged decreases in forecasted oil and natural gas commodity prices triggered the re-evaluation of E&E assets in the Haro South CGU, which were previously impaired in 2012 as a result of management indefinitely delaying future development plans in the area. E&E assets in the Central CGU were also impaired in the current quarter as a result of changes in management's future development plans to realize the value of E&E assets in the CGU primarily through its sale rather than through future development. Impairment charges recognized could be reversed in future periods should forward commodity prices recover or should development plans change.

The YTD 2014 impairment charge of $2.3 million related to the write down required on assets classified as held for sale as at March 31, 2014 to fair value. The assets were held in the Peace River Arch CGU and were sold to a third party in Q2 2014.

The components of D&D are as follows:

Depletion, depreciation and impairments	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
(000s)					
Depletion & depreciation	**$ 12,703**	$ 23,858	$ 13,801	**$ 26,504**	$ 43,048
Impairment	**91,223**	-	-	**91,223**	2,318
Total	**$ 103,926**	$ 23,858	$ 13,801	**$ 117,727**	$ 45,366
($/boe)					
Depletion & depreciation	**$ 14.17**	$ 18.11	$ 13.87	**$ 14.01**	$ 16.38
Impairment	**101.78**	-	-	**48.23**	0.88
Total	**$ 115.95**	$ 18.11	$ 13.87	**$ 62.24**	$ 17.26

Environmental Liabilities and Insurance Receivable

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 fell within the Company's insurance coverage subject to a $0.5 million deductible per incident. The Company chose 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. The Company has received $2.0 million of insurance proceeds to June 30, 2015. As of June 30, 2015, $3.8 million of clean-up and remediation costs have been paid with a further $0.1 million recorded in accrued liabilities for work performed to June 30, 2015 and $0.6 million accrued in other liabilities for future costs expected to be incurred.

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 total estimated clean-up and remediation costs are expected to be $23.9 million. The Company has received $21.1 million of insurance proceeds to June 30, 2015. The Company has paid $22.1 million in clean-up and remediation costs as at June 30, 2015 with a further $1.8 million accrued in other liabilities for future costs expected to be incurred.

Insurance Receivable

Spyglass has recorded $4.7 million in accounts receivable for insurance receivable as at June 30, 2015. Spyglass has evaluated the credit worthiness of its insurance providers and concluded it to be adequate. The receivable balance is attributed to expenditures incurred for which reimbursement is pending and as well as for future costs expected to be incurred.

Other Income

Q2 2015 other income of $1.8 million is comprised of $1.7 million of non-cash gains on the disposition of non-core producing properties and undeveloped land. Q2 2015 cash other income includes $0.1 million of marketing revenue. During the quarter, the Company also reviewed its working capital balances in response to the deteriorated economic environment. This resulted in an additional provision to bad debt expense of $1.1 million as well as the de-recognition of $1.2 million of provisions related to a predecessor company that was recorded upon the amalgamation of Pace Oil & Gas Ltd., Charger Energy Corp., and AvenEx Energy Corp., to form Spyglass in 2013. Q2 2014 and YTD 2014 other income of $4.4 million and $5.6 million respectively also consisted primarily of non-cash gains on the disposition of non-core producing properties in the quarter as well as gains on the sale of investments. Other income was nil in Q1 2015.

The following is a breakdown of other income:

Other Income		**Q2 2015**		Q2 2014		Q1 2015		**YTD 2015**		YTD 2014
(000s)										
Cash other income	**$**	**161**	$	62	$	-	**$**	**161**	$	135
Non-cash other income (loss)		**1,667**		4,369		-		**1,667**		5,487
Total	**$**	**1,828**	$	4,431	$	-	**$**	**1,828**	$	5,622
($/boe)										
Cash other income	**$**	**0.18**	$	0.05	$	-	**$**	**0.09**	$	0.05
Non-cash other income (loss)		**1.86**		3.32		-		**0.88**		2.09
Total	**$**	**2.04**	$	3.37	$	-	**$**	**0.97**	$	2.14

Deferred Taxes

Spyglass recorded deferred taxes of nil in Q2 2015 compared to an expense of $2.1 million in Q2 2014 and $62.5 million in Q1 2015. The Q2 2015 deferred tax expense incorporates an increase in the Alberta corporate tax rate from 10% to 12% which was substantially enacted in the current quarter. On a YTD basis, YTD 2015 deferred tax expense was $62.5 million versus a deferred tax recovery of $1.8 million for the same period in 2014. During the Q1 2015 $66.8 million of deferred tax assets were derecognized. As at June 30, 2015, the Company has approximately $848 million of tax pools available for deduction against future taxable income for which no deferred tax asset has been recognized.

Funds from Operations and Net Loss

For Q2 2015, funds from operations totalled $11.4 million, $0.09 per basic and diluted share compared to $19.0 million, $0.15 per basic and diluted share in Q2 2014 and $4.8 million or $0.04 per basic and diluted share in Q1 2015.

For Q2 2015, funds from operations decreased $7.6 million from Q2 2014. Operating netbacks at $13.57 per boe in Q2 2015 were $13.74 per boe lower than $27.31 per boe in Q2 2014. This drop incorporates a $24.60 per boe decline in sales price resulting from the significant decline in commodity prices. This along with a lower percentage of production weighted toward crude oil and liquids contributed to a $22.1 million decrease in field cash flows. Decreased production volumes contributed to a further decrease in field cash flows of $24.4 million. These reductions were offset by lower royalties and operating expenses of $12.8 million and $8.8 million respectively and higher gains on financial derivative instruments of $12.4 million.

Compared to Q1 2015, funds from operations increased $6.6 million in Q2 2015 reflecting a $4.9 million increase in revenues due to increased commodity pricing and a $6.2 million decrease in operating expenses offset by a $2.8 million reduction in revenue due to lower production volumes and a $3.6 million reduction in gains on financial derivative instruments.

For Q2 2015, the Company had a net loss of $98.8 million or $0.77 per basic and diluted share compared to a net income of $0.8 million in Q2 2014 or $0.01 per basic and diluted share and a net loss of $80.0 million in Q1 2015 or $0.63 per basic and diluted share. Compared to Q2 2014, the increase in net loss is primarily due to impairment charges recognized in Q2 2015 as well as significant declines in petroleum and natural gas sales as the result of decreases in commodity prices. The increase in net loss from $80.0 million in Q1 2015 to $98.8 million in Q2 2015 was largely driven by impairment charges recognized in Q2 2015 partially offset by the dereocognition of deferred tax assets in Q1 2015.

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

($/boe)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Sales price	**$ 33.35**	$ 57.95	$ 27.87	**$ 30.46**	$ 58.70
Royalties	**(0.79)**	(10.27)	(1.71)	**(1.27)**	(10.49)
Operating expenses	**(17.04)**	(18.27)	(21.58)	**(19.43)**	(20.28)
Transportation expenses	**(1.95)**	(2.10)	(2.21)	**(2.09)**	(2.23)
Operating netback	**$ 13.57**	$ 27.31	$ 2.37	**$ 7.67**	$ 25.70
Other non-cash expenses	**0.02**	-	0.01	**0.02**	-
Cash other income (expense)	**0.18**	0.05	-	**0.09**	0.05
Realized gain (loss) on financial derivative instruments	**4.56**	(6.31)	7.75	**6.24**	(6.03)
G&A	**(2.92)**	(3.35)	(3.00)	**(2.96)**	(3.38)
Interest	**(2.66)**	(3.25)	(2.27)	**(2.45)**	(3.01)
Cash flow netback	**$ 12.75**	$ 14.45	$ 4.86	**$ 8.61**	$ 13.33
Unrealized gain (loss) on financial derivative instruments	**(7.36)**	4.16	(7.10)	**(7.22)**	(1.46)
Other non-cash expenses	**(0.02)**	-	(0.01)	**(0.02)**	-
Non-cash other income (expense)	**1.86**	3.32	-	**0.88**	2.09
Depletion, depreciation and impairment	**(115.95)**	(18.11)	(13.87)	**(62.24)**	(17.26)
Accretion	**(1.58)**	(1.10)	(1.40)	**(1.48)**	(1.09)
Transaction costs	**-**	-	-	**-**	-
Long-term incentive compensation	**0.12**	(0.54)	(0.05)	**0.03**	(0.46)
Deferred taxes	**-**	(1.56)	(62.78)	**(33.03)**	0.69
Net income (loss)	**$ (110.18)**	$ 0.62	$ (80.35)	**$ (94.47)**	$ (4.16)

The following table provides reconciliations to the change in funds from operations and net income for Q2 2015 to Q2 2014 and for Q2 2015 to Q1 2015.

Change in Funds from Operations and Net Income (loss) (000s)	**Q2 2015 to Q2 2014**		**Q2 2015 to Q1 2015**	
	Funds from Operations	Net income / (loss)	**Funds from Operations**	Net income / (loss)
Comparative period	**$ 19,043**	$ 815	**$ 4,838**	$ (79,963)
Increase (decrease) in revenue:				
Change in production volumes	**(24,384)**	(24,384)	**(2,756)**	(2,756)
Change in prices	**(22,054)**	(22,054)	**4,911**	4,911
Change in royalties	**12,822**	12,822	**997**	997
(Increase) decrease in expenses:				
Operating	**8,801**	8,783	**6,207**	6,201
Transportation	**1,012**	1,012	**448**	448
Finance charges	**1,895**	1,931	**(124)**	(144)
General and administration	**1,794**	1,794	**368**	368
Long-term incentive compensation	**-**	819	**-**	156
Depletion, depreciation and impairment	**-**	(80,068)	**-**	(90,125)
Deferred tax	**-**	2,054	**-**	62,482
Transaction costs	**-**	-	**-**	-
Increase (decrease) in:				
Other income	**99**	(2,603)	**161**	1,828
Gains (losses) on financial derivative instruments	**12,395**	326	**(3,627)**	(3,156)
Current period	**$ 11,423**	$ (98,753)	**$ 11,423**	$ (98,753)

Capital Expenditures and Dispositions

Capital expenditures in Q2 2015 were limited to $2.3 million with $1.0 million spent on workover, maintenance and optimization activities, $0.4 million on facilities, turnarounds and tie-ins, $0.7 million on office costs which was substantially capitalized G&A, and the remaining $0.2 million on land. The majority of the capital spend focused on maintenance and optimization activities as well as on the tie-in of one gross (0.1 net) non-operated well that was drilled in Q1 2015 in the South core area at Herronton.

In Q2 2015, the Company closed the sale of certain non-core producing properties in the province of Alberta for proceeds of $2.7 million, net of adjustments. The net impact of these transactions was a non-cash gain of $1.7 million which was recognized in the Consolidated Statement of Income (Loss).

YTD 2015 capital expenditures totalled $7.9 million with $3.1 million spent on drilling, completion, maintenance and optimization activities, $3.0 million on facilities, pipelines, equipping and tie-ins, $1.5 million on office costs which was substantially capitalized G&A, and the remaining $0.3 million on land and seismic. The majority of the capital spend focused on maintenance activities as well as the conclusion of pipeline remediation activities at Dixonville which commenced in 2014, the drilling, completion and tie-in of one gross (0.1 net) non-operated in the South core area at Herronton and on the tie-in of two gross (2 net) wells that were drilled in Q4 2014.

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

Capital Expenditures (000s)	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Land	**$ 228**	$ 406	$ 53	**$ 281**	$ 630
Geological and geophysical	**-**	184	11	**11**	295
Drilling and completions	**1,046**	12,087	2,048	**3,094**	25,608
Facilities and equipment	**416**	1,403	2,566	**2,982**	3,950
Office and capitalized G&A	**653**	1,322	898	**1,551**	2,766
Capital Expenditures	**$ 2,343**	$ 15,402	$ 5,576	**$ 7,919**	$ 33,249
Acquisitions	**-**	2,458	-	**-**	2,458
Dispositions	**(2,710)**	(7,344)	-	**(2,710)**	(12,672)
Total capital expenditures and acquistions net of dispostions	**$ (367)**	$ 10,516	$ 5,576	**$ 5,209**	$ 23,035
Exploration and evaluation expenditures	**$ 124**	$ 613	$ 145	**$ 269**	$ 809
Property, plant and equipment expenditures	**(491)**	9,903	5,431	**4,940**	22,226
Total capital expenditures and acquisitions net of dispositions	**$ (367)**	$ 10,516	$ 5,576	**$ 5,209**	$ 23,035

Spyglass has approximately 369,000 net acres of undeveloped land under lease at June 30, 2015.

Equity

On December 18, 2014, the TSX accepted the Company's notice to make a normal course issuer bid to purchase its outstanding common shares on the open market. The TSX authorized the Company to purchase up to 12,460,689 common shares during the period from December 22, 2014 to December 21, 2015. Shares purchased under the bid will be cancelled. During 2014, there were 272,000 shares purchased at a weighted average cost of $0.36 per share. As the carrying value of the purchased shares was $3.86 per share, the $1.0 million difference between the carrying amount and the purchased amount was recorded as contributed surplus. Spyglass has not repurchased any further common shares up to the date of this MD&A.

The Company has no dilutive instruments outstanding.

Share Information	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Shares Outstanding					
Basic	**127,804,720**	128,076,720	127,804,720	**127,804,720**	128,076,720
Diluted	**127,804,720**	128,076,720	127,804,720	**127,804,720**	128,076,720
Weighted average shares outstanding					
Basic	**127,804,720**	128,076,720	127,804,720	**127,804,720**	128,076,720
Diluted	**127,804,720**	128,076,720	127,804,720	**127,804,720**	128,076,720

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 the periods indicated:

Trading History on the TSX	**Q2 2015**	Q2 2014	Q1 2015	**YTD 2015**	YTD 2014
Trading price					
High	**$ 0.37**	$ 1.97	$ 0.50	**$ 0.50**	$ 2.14
Low	**$ 0.19**	$ 1.64	$ 0.26	**$ 0.19**	$ 1.64
Close	**$ 0.20**	$ 1.73	$ 0.30	**$ 0.20**	$ 1.73
Volume (000's)	**6,880**	22,844	11,005	**17,885**	42,632

On the over the counter market, 8.1 million shares were traded YTD 2015 compared to 11.8 million shares in YTD 2014.

On June 30, 2015 Spyglass amended its $200 million credit facility with a syndicate of banks. Upon amendment, the facility consists of a $100 million syndicated borrowing base revolving term facility and a $100 million syndicated reducing term facility. Both facilities have a maturity date of May 29, 2016. The reducing term facility is required to be reduced to $25 million by January 31, 2016 and is to be permanently reduced by repayments of the facility which include, but are not limited to, proceeds from property dispositions, issuance of equity securities, proceeds from early termination of derivative financial instruments, insurance proceeds and proceeds from the issuance of new debt. At June 30, 2015, $176.4 million was drawn on the facility and the Company had a working capital deficit and net debt of $184.5 million (excluding current portion of financial derivative instruments). The available level of credit under the borrowing base revolving term facility is subject to semi-annual review and may be adjusted for changes in reserves, commodity prices and other factors. The Company is subject to certain non-financial covenants in its credit facility agreement. Covenants include reporting requirements, permitted and expected dispositions, permitted and required financial derivatives, permitted encumbrances and other standard business operating covenants. The Company is also subject to minimum liquidity requirements. As at June 30, 2015 the Company is in compliance with all covenants. The Company had $2.2 million in letters of credit outstanding at June 30, 2015. Subsequent to June 30, 2015, the Company made $2.5 million of repayments to the reducing term facility.

Management recognizes the difficulties of operating in the current commodity price environment and has taken steps to manage spending and leverage. The Company plans to remedy its working capital deficit through recapitalization and asset divestiture opportunities. Additionally, cost reduction and capital management initiatives have been implemented and as such the Company has been able to maintain positive funds from operations. The Company continually monitors its capital structure and capital program in response to changes in business conditions including changes in economic condition, forecasted commodity prices and resulting cash flows, debt levels and the risk and timing of capital investments.

The condensed interim financial statements have been prepared in accordance with IFRS on a going concern basis, which asserts that the Company has the ability to realize its assets and discharge its liabilities and commitments in the normal course of business. The reducing term facility is required to be reduced to $25 million by January 31, 2016. The Company is in the process of identifying and pursuing recapitalization and divestiture opportunities and is taking steps to manage its spending and leverage including the implementation of cost reduction and capital management initiatives. There is no assurance that the Company will be able to access recapitalization and divestiture opportunities in order to repay the reducing term facility in accordance with the timing required under the credit facility agreement. Should the Company fail to make repayments of the reducing term facility in accordance with the requirements of the credit facility agreement, outstanding borrowings may become due and payable immediately. These circumstances result in material uncertainty surrounding the Company's ability to continue as a going concern and lend significant doubt as to the ability of the Company to meet its obligations as they come due and, accordingly, the appropriateness of the use of accounting principles applicable to a going concern.

The Company currently continues to meet all of its obligations with respect to ongoing operations. The condensed interim consolidated financial statements do not reflect the adjustments to the carrying amounts of the Company's assets, liabilities, revenues, expenses and balance sheet classifications that would be necessary if the going concern assumption is not appropriate. Such adjustments could be material.

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
Bank debt and related interest	**$ 184,320**	$ 184,320	$ -	$ -	$ -
Firm transportation charges	**6,004**	2,188	2,564	625	627
Operating leases	**25,575**	3,525	7,271	7,253	7,526
Total Contractual Obligations	**$ 215,899**	$ 190,033	$ 9,835	$ 7,878	$ 8,153

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

The Company estimates it will incur costs of approximately $358.9 million on an undiscounted basis 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 $49.1 million and has been recorded on the Company's balance sheet as at June 30, 2015. 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.

Financial Instruments

Financial instruments comprise accounts receivable, financial derivative instruments, accounts payable and accrued liabilities, long-term incentive plan liability and bank debt. The fair values of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities 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 bank 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, 2014.

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) (2013) published by the Committee of Sponsoring Organizations of the Treadway Commission. The certification of interim filings for the period ended June 30, 2015 requires that the Company disclose in the MD&A and changes in the Company's internal controls that have materially affected, or are likely to materially affect, the Company's internal controls over financial reporting during the three months ended June 30, 2015. The Company confirms that there were no changes in the Company's internal controls during Q2 2015 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, 2014 and 2013.

Financial Reporting Update

Pronouncements and amendments for annual periods beginning on or after January 1, 2015 are disclosed in the Company's year end audited consolidated financial statements for the year ended December 31, 2014. 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 2014 Annual Information Form filed on SEDAR at www.sedar.com.

Selected Quarterly Information

Financial	2015		2014				2013	
(000s, except per share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**$ 29,888**	$ 27,733	$ 48,884	$ 61,731	$ 76,326	$ 77,917	$ 65,909	$ 80,859
Cash flow from (used in) operations	**6,760**	9,754	8,938	8,398	27,470	10,342	9,360	14,046
Funds from operations	**11,423**	4,838	11,883	11,902	19,043	16,026	11,426	21,547
Per share- basic	**0.09**	0.04	0.09	0.09	0.15	0.13	0.09	0.17
Per share- diluted	**0.09**	0.04	0.09	0.09	0.15	0.13	0.09	0.17
Net income (loss)	**$ (98,753)**	$ (79,963)	$ (140,753)	$ (4,188)	$ 815	$ (11,697)	$ (16,866)	$ (1,402)
Per share- basic	**(0.77)**	(0.63)	(1.10)	(0.03)	0.01	(0.09)	(0.13)	(0.01)
Per share- diluted	**(0.77)**	(0.63)	(1.10)	(0.03)	0.01	(0.09)	(0.13)	(0.01)
Capital expenditures	**$ 2,343**	$ 5,576	$ 15,205	$ 29,078	$ 15,402	$ 17,847	$ 14,991	$ 24,559
Property acquisitions	**-**	-	-	-	2,458	-	-	-
Dispositions	**(2,710)**	-	(110,935)	(42,836)	(7,344)	(5,328)	(12,515)	(10,199)
Total capital expenditures and acquisitions net of dispositions	**(367)**	5,576	(95,730)	(13,758)	10,516	12,519	2,476	14,360
Bank debt	**176,400**	182,100	174,700	267,400	290,900	294,900	287,000	277,000
Net debt	**184,478**	195,677	193,819	293,762	270,828	307,150	300,508	291,997
Total assets	**345,708**	480,596	561,545	833,942	881,033	897,155	892,328	921,752
Dividends Declared	**-**	-	3,843	6,724	8,645	8,645	8,645	8,645
Per share- basic	**-**	-	0.0300	0.0525	0.0675	0.0675	0.0675	0.0675
Shares outstanding (000s)								
Basic	**127,805**	127,805	127,805	128,077	128,077	128,077	128,077	128,077
Diluted	**127,805**	127,805	127,805	128,077	128,077	128,077	128,077	128,077
Weighted average shares outstanding (000s)								
Basic	**127,805**	127,805	128,062	128,077	128,077	128,077	128,077	128,077
Diluted	**127,805**	127,805	128,062	128,077	128,077	128,077	128,077	128,077
Operations								
Average daily production								
Oil (bbls/d)	**3,809**	4,112	5,389	5,045	6,164	6,784	7,198	7,473
NGLs (bbls/d)	**275**	292	280	410	535	391	647	383
Natural gas (Mcf/d)	**34,589**	39,923	41,981	48,379	46,647	44,312	48,164	51,533
Combined (boe/d)	**9,849**	11,058	12,666	13,518	14,474	14,560	15,873	16,445
Operating netback ($/boe)	**$ 13.57**	$ 2.37	$ 13.49	$ 19.60	$ 27.31	$ 24.10	$ 15.09	$ 22.09

In 2014, the Company drilled 21 gross (17.3 net) wells, and has drilled one gross (0.1 net) wells year to date in 2015.

Production averaged 9,849 boe/d in Q2 2015, lower than Q1 2015 production of 11,058 boe/d and 2014 annual production average of 13,798, reflecting the impact of property dispositions which closed in 2014 of $166 million. Commodity prices have been volatile over the previous eight trailing quarters which led to impairment losses in Q2 2015 of $91.2 million and in Q4 2014 of $126.6 million, which contributed to net losses of $98.8 million and $140.8 million in the respective quarters. The net loss of $80.0 million in Q1 2015 includes deferred tax expense of $62.5 million that was incurred upon the derecognition of deferred tax assets in that quarter. Oil and natural gas prices started to decline in Q3 2014 continuing to decline through Q1 2015 when lows were reached. This, along with asset dispositions occurring throughout 2014 resulted in continued declines in petroleum and natural gas sales from Q2 2014, with sales of $76.3 million, to Q1 2015, with sales of $27.7 million. Q2 2015 oil prices increased slightly from Q1 2015 levels, contributing to slightly higher Q2 2015 sales of $29.9 million. However, oil price increases were partially offset by slight gas prices decrease from Q1 2015 levels as well as decreased production in the quarter which primarily resulted from natural declines.

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.