Management's Discussion and Analysis

For the three months and year ended December 31, 2014

March 31, 2015

Strategic Oil & Gas Ltd. ("Strategic" or the "Company") is a publicly-traded oil and gas exploration and production company, with operations focused on light oil development in northern Alberta. The following is Management's Discussion and Analysis ("MD&A") of Strategic's consolidated operating and financial results for the three months and year ended December 31, 2014, as well as information concerning the Company's future outlook based on currently available information. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2014 and 2013, together with the accompanying notes, which have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Further information with respect to the Company can be found on its website at www.sogoil.com and on the SEDAR website: www.sedar.com.

FINANCIAL AND OPERATIONAL SUMMARY

	Three Months Ended December 31			**Year Ended December 31**		
	2014	2013	% change	**2014**	2013	% change
Financial ($thousands, except per share amounts)						
Oil and natural gas sales	**18,790**	15,377	22	**82,466**	78,738	5
Funds from (used in) operations [1]	**4,974**	(320)	-	**12,270**	17,162	(29)
Per share basic & diluted	**0.01**	0.00	100	**0.03**	0.08	(63)
Cash flow from operating activities	**8,134**	2,122	283	**13,396**	18,493	(28)
Per share basic & diluted	**0.02**	0.01	100	**0.04**	0.08	(50)
Net loss	**(117,321)**	(9,852)	1,090	**(129,490)**	(22,316)	480
Per share basic & diluted	**(0.22)**	(0.04)	450	**(0.34)**	(0.10)	240
Capital expenditures (excluding acquisitions)	**24,456**	29,484	(17)	**101,319**	119,151	(15)
Net debt	**48,399**	82,547	(41)	**48,399**	82,547	(41)
Operating						
Average daily production						
Oil and NGL (bbl per day)	**2,694**	1,888	43	**2,343**	2,339	-
Natural gas (mcf per day)	**7,382**	5,753	28	**6,715**	5,588	20
Barrels of oil equivalent (boe per day)	**3,925**	2,847	38	**3,462**	3,270	6
Average prices						
Oil & NGL, before risk management ($ per bbl)	**65.67**	77.25	(15)	**83.56**	84.35	(1)
Oil & NGL, including risk management ($ per bbl)	**70.49**	74.67	(6)	**76.66**	81.31	(6)
Natural gas ($ per mcf)	**3.70**	3.71	-	**4.49**	3.30	36
Natural gas, including risk management ($ per mcf)	**3.76**	3.71	1	**4.32**	3.30	31
Netback ($ per boe)						
Petroleum and natural gas sales	**52.04**	58.72	(11)	**65.26**	65.97	(1)
Royalties	**9.19**	11.93	(22)	**13.80**	14.51	(5)
Operating costs	**22.83**	34.54	(34)	**25.73**	24.02	7
Transportation costs	**1.55**	3.64	(58)	**2.50**	3.56	(30)
Operating Netback ($ per boe) [1]	**18.47**	8.61	115	**23.23**	23.88	(3)
Common Shares (thousands)						
Common shares outstanding, end of period	**542,319**	260,601	108	**542,319**	260,601	108
Weighted average common shares (basic)	**539,483**	258,318	109	**381,240**	217,604	75
Weighted average common shares (diluted)	**539,483**	258,318	109	**381,240**	217,604	75

(1) In 2014, revenues are presented net of pipeline tariff charges on oil sales which occur after title to the product has passed to the customer. Prior year amounts for revenue and transportation costs have been reclassified to conform to the current period presentation.

(2) Funds from operations, net debt and operating netback are non-IFRS measurements; see "Non-IFRS Measurements" in this MD&A.

About Strategic

Strategic is a junior oil and gas company committed to growth by exploiting its light oil assets primarily in northern Alberta. The Company relies on its extensive subsurface and reservoir experience to develop its asset base and grow production and cash flows while managing risk. The Company maintains control over its resource base through high-working interest ownership in wells, construction and operation of its own processing facilities and a significant undeveloped land base and opportunity inventory. Strategic's primary operating area is at Marlowe, Alberta. The Company also operates oil and gas production and processing facilities at Bistcho, Alberta and Cameron Hills in the Northwest Territories, as well as minor non-core oil properties in southern Alberta.

FOURTH QUARTER SUMMARY

- Production increased 38 percent from 2,847 boed for the three months ended December 31, 2013 to 3,925 boed for the current quarter, primarily due to the Company's successful Muskeg drilling program at Marlowe. Production for the fourth quarter of 2013 was affected by a 25 day shutdown related to a plant turnaround and facility expansion at Marlowe. Production volumes for the current period were also positively impacted by the sale of 24,000 barrels of oil (260 bbl/d) from inventories held at September 30, 2014 which could not be sold in the third quarter as a result of a temporary shut-down of a third party sales oil pipeline. Strategic routed Marlowe oil production to its company-owned storage facility at Bistcho during the shut-down and was able to avoid curtailing production due to this event.

- Funds from (used in) operations increased significantly to $5.0 million from $(0.3) million for the comparable quarter in 2013, due to higher production levels and lower production and finance costs. The operating netback increased to $18.47/boe from $8.61/boe for the fourth quarter of 2013 despite an 11 percent reduction in realized prices.

- Capital expenditures of $24.5 million for the current quarter included drilling five wells at Marlowe, as well as completion of road construction and other projects required to continue development of the Muskeg fairway in north Marlowe throughout 2015.

- Strategic completed a private placement of common shares at $0.40 per common share and flow-through common shares at $0.44 per flow-through share, issuing a total of 181.3 million shares for total net proceeds of $73.0 million. Approximately 90 percent of the private placement closed on September 30, 2014 with the remainder closing on October 15, 2014.

ANNUAL SUMMARY

- Production increased by 6 percent from 3,270 boed in 2013 to an average of 3,462 boed in 2014.

- Funds from operations decreased 29 percent from $17.2 million in 2013 to $12.3 million in 2014 as higher revenues due to increased production levels were more than offset by increases in realized losses on risk management contracts and operating costs. The operating netback at Bistcho/Cameron Hills was challenged in 2014 as a result of declining production and higher repair & maintenance expenses compared to 2013, reducing funds from operations for the current year.

- Capital expenditures totaled $101.3 million for the twelve months ended December 31, 2014 as compared to $119.2 million for 2013. Approximately 91 percent of capital spending was directed to the Company's light oil asset at Marlowe. Drilling, completions and equipping expenditures decreased 6 percent to $68.5 million for the current year from $72.7 million for 2013 despite an increase in the number of wells drilled to 14 in 2014 from 12 the previous year. Pipeline and facility expenditures decreased 24 percent from 2013 levels to $29.9 million, and included construction of a major sales pipeline to transport oil from Marlowe to the Rainbow sales pipeline system, as well as a gathering line from West Marlowe to one of the Company's oil processing facilities and major plant turnarounds at Bistcho/Cameron Hills.

- The sales oil pipeline, a key aspect of the Company's growth strategy, was completed in the first quarter of 2014. The pipeline was operational on March 31, 2014 and contributed to a reduction of 30 percent in transportation costs over 2013 levels, and a 58 percent reduction in the fourth quarter of 2014 relative to the last three months of 2013. In 2015 the Company has discontinued the use of railcars for a portion of oil sales in order to take full advantage of the lower costs of the sales oil pipeline.

- Strategic increased its proved and probable oil and gas reserves by 1.2 MMboe compared to the previous year, despite a reserves reduction due to economic factors of 2.1 MMboe related primarily to Bistcho/Cameron Hills, as determined by the Company's independent reserve evaluators McDaniel and Associates Consultants Ltd. ("McDaniel") at December 31, 2014. The Company added 4.7 MMboe of proved and probable reserves in 2014 at Marlowe, excluding production, for a reserve replacement ratio of 403 percent.

- Net loss increased to $129.5 million for 2014 compared to a loss of $22.3 million for 2013, primarily as a result of an impairment charge of $114.0 million for the current year driven by the significant decline in oil prices in the fourth quarter.

ADVISORIES

Basis of Presentation

This discussion and analysis of Strategic's oil and natural gas production, reserves and related performance measures is presented on a working-interest, before royalty basis. For the purpose of calculating unit information, the Company's production and reserves are reported in barrels of oil equivalent (boe). Boe may be misleading, particularly if used in isolation. A boe conversion ratio for natural gas of 6 Mcf: 1 boe has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and our revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, environmental and decommissioning liabilities, income taxes, and the determination of proved and probable reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Non-IFRS Measurements

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities.

"Funds from operations" is a term used to evaluate operating performance and assess leverage. The Company considers funds from operations an important measure of its ability to generate funds necessary to finance operating activities, capital expenditures and debt repayments if any. Funds from operations are calculated based on cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures. Funds from operations as presented is not intended to represent cash flow from operating activities, net earnings, or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles funds from operations to cash provided by operating activities:

($thousands)	Three months ended December 31 **2014**	2013	Year ended December 31 **2014**	2013
Cash generated by operating activities	**8,134**	2,122	**13,396**	18,493
Expenditures on decommissioning liabilities	**(2)**	103	**1,745**	762
Change in non-cash working capital	**(3,158)**	(2,545)	**(2,871)**	(2,093)
Funds from operations	**4,974**	(320)	**12,270**	17,162

"Operating Netback" is used to evaluate operating performance of crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue excluding realized and unrealized gains and losses on risk management contracts, less royalties, operating and transportation costs. There is no IFRS measurement that would be directly comparable to operating netbacks.

"Adjusted net working capital (deficiency)" and "net debt" are used to assess capital requirements and leverage, as well as evaluate funds available on the Company's credit facility. Adjusted net working capital (deficiency) is calculated as current assets less current liabilities, excluding bank debt, deferred price premium on flow through shares and any assets or liabilities related to risk management contracts. Net debt is calculated as bank debt plus adjusted net working capital deficiency, or less adjusted net working capital. A reconciliation of adjusted net working capital and net debt to working capital deficiency is as follows:

($thousands)	**December 31, 2014**	December 31, 2013
Current assets	**14,899**	9,685
Current liabilities	**(59,838)**	(101,127)
Working capital deficiency	**(44,939)**	(91,442)
Add back: deferred price premium on flow-through shares	-	1,619
risk management contract liability (asset)	**(3,460)**	7,276
Net debt	**(48,399)**	(82,547)
Bank debt	**29,016**	63,775
Adjusted net working capital (deficiency)	**(19,383)**	(18,772)

Going Concern

Strategic's consolidated financial statements have been prepared on a going concern basis. The going concern basis of presentation assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. For the year ended December 31, 2014, the Company reported a net loss of $129.5 million. At December 31, 2014, the Company had net debt of $48.4 million and an accumulated deficit of $201.0 million. Strategic's cash flows and compliance with debt covenants are highly dependent on realized oil pricing in 2015. Sustained low commodity prices will put pressure on the Company's cash flows, and will lead to a material uncertainty that may cast significant doubt upon the Company's ability to continue as a going concern.

The Company anticipates being in violation of the working capital covenant of its credit facility as at March 31, 2015. Strategic is working proactively with its lenders regarding the facility and the covenants. In order to address the working capital violation, the Company is evaluating measures such as asset sales, other third party funding alternatives and elimination of all non-critical capital spending programs. There can be no assurance that these initiatives will be successful.

The consolidated financial statements do not reflect adjustments that would be necessary if the going concern basis was not appropriate. The appropriateness of the going concern basis is dependent upon, among other things, the ability to obtain debt or equity financing, a joint venture or a sale of assets in order to have sufficient funding to meet its obligations that enables the Company to continue as a going concern, the ability to generate sufficient cash from operations and future profitable operations.

PERFORMANCE OVERVIEW

In 2014 the Company continued to execute on its corporate strategy to pursue its light oil development opportunities at Marlowe in northern Alberta, as well as constructing a pipeline to connect Marlowe to the Rainbow sales pipeline system and increase the handling capacity of its existing infrastructure. The Company's focus in the first quarter of the year was on completing the Bistcho sales oil pipeline, which connects oil production from Marlowe to the Rainbow pipeline system over a total distance of 115 kilometers. Strategic also drilled 3 Muskeg wells in the first quarter of 2014, and followed up on its success with an 11 well program at Marlowe in the second half of the year, comprised of 9 horizontal wells and 2 Keg River vertical wells. The Company's drilling success rate was 100 percent for the year.

Average daily production increased 6 percent from 3,270 boed in 2013 to 3,462 boed in 2014 due to Muskeg drilling activities and a full year of production from assets acquired at Bistcho/Cameron Hills in February 2013. Corporate operating netbacks decreased slightly to $23.23 per boe in 2014 from $23.88 per boe in 2013, due to an increase in workovers and higher than expected costs at Bistcho/Cameron Hills, partially offset by a lower royalty rate per boe as a higher proportion of the Company's production was contributed by newly drilled wells, which benefit from a reduced first-year royalty rate. Strategic continued to generate a competitive netback at Marlowe, where it has assembled a concentrated base of land and infrastructure and achieved substantial success in delineating the Muskeg resource in 2014. This area will be the focus of development for the Company in future years.

Reserves

In accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), the Company's oil, natural gas and natural gas liquids ("NGL") reserves were evaluated by McDaniel as at December 31, 2014. The reserves report has been prepared in accordance with the definitions, procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities. Gross reserves included below are Strategic's working interest reserves before royalty burdens.

Strategic's reserves at December 31, 2014 are summarized below.

Reserves [1]	Light and Medium Crude Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Proved Producing	3,013	70	6,131	-	4,105
Proved Non-Producing	545	27	1,168	-	767
Proved Undeveloped	1,756	-	3,435	-	2,329
Total Proved	**5,314**	**98**	**10,733**	**-**	**7,201**
Total Probable	**4,904**	**36**	**10,711**	**-**	**6,724**
Total Proved and Probable	**10,218**	**133**	**21,444**	**-**	**13,925**

(1) The recovery and reserve estimates of Strategic's oil, natural gas and NGL reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. Tables may not add due to rounding.

Strategic added 4.6 MMboe of proved and probable reserves in 2014 through drilling activities and well optimization. However low commodity prices contributed to a reduction in reserves due to economic factors of 2.1 MMboe, 99 percent of which occurred outside of Marlowe. The Company's reserve replacement ratio after considering the reduction due to economic factors was 196 percent. Proved reserves increased 8 percent to 7.2 MMboe (75 percent oil) from 6.7 MMboe at year-end 2013. Proved and probable reserves increased 1.2 MMboe (9 percent) from 12.7 MMboe at year-end 2013 to 13.9 MMboe (74 percent oil) at December 31, 2014. Pre-tax net asset value of the Company's proved and probable reserves, using McDaniel's forecast pricing and discounted at 10 percent, increased to $196 million at December 31, 2014 from $180 million at December 31, 2013 despite the precipitous drop in commodity prices during the year.

Muskeg Stack Resource Assessment

In order to quantify the future reserve potential, a resource assessment was conducted on the Muskeg Stack, which covers the Company's assets in the Marlowe area, by McDaniel with an effective date of January 1, 2015. The assessment identified an additional 198 Muskeg drilling locations not currently reflected in the Company's reserve report. The results of this assessment are summarized below.

Petroleum Initially in Place[(1,2)]

Category	Exploitable Mbbl	Non-Exploitable Mbbl	Total MMbbl
Discovered Resources	113,551	65,225	178,776
Undiscovered Resources	215,248	522,241	737,489
Total Resources	328,799	587,466	916,265

Contingent Resources[(3,5)]

Category	Contingent Resource Oil (Mbbl)	Contingent Resource Natural gas (MMcf)	Contingent Resource Oil equivalent (Mboe)
Low estimate	2,635	6,423	3,706
Best estimate	4,185	11,718	6,138
High estimate	6,200	19,763	9,494

Prospective Resources[(4,5)]

Category	Prospective Resource Oil (Mbbl)	Prospective Resource Natural gas (MMcf)	Prospective Resource Oil equivalent (Mboe)
Low estimate	14,195	34,600	19,961
Best estimate	22,545	63,126	33,066
High estimate	33,400	106,463	51,144

(1) The exploitable component of the Petroleum Initially in Place was constrained to areas with greater than 4,000 Mbbl per section as a means to high grade lands that are amenable to exploitation. No recoverable resources were assigned to lands outside this exploitable region.
(2) Discovered resources have been assigned on those lands that are proximal to existing production. Undiscovered resources have been assigned on those lands where there is a strong indication of the presence of the resource by way of existing vertical penetrations, but productivity has not yet been demonstrated.
(3) Contingent resources have an associated chance of development. Contingencies include economic, regulatory, market and facility, and corporate commitment considerations. There is no certainty that any portion of the contingent resources will be developed, nor whether it will be commercially viable to produce any portion of the resources.
(4) Prospective resources have both an associated chance of discovery (geological chance of success) and a chance of development. There is no certainty that any portion of the prospective resources will be discovered and developed, nor whether it will be commercially viable to produce any portion of the resources.
(5) The resource estimates may differ materially upon consideration of discovery and development risk and consideration of economics and financing.

Discovered Petroleum Initially In Place (DPIIP), as defined in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. Contingent Resources are defined in COGE Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Undiscovered Petroleum Initially-In-Place (UPIIP) (equivalent to Undiscovered Resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of UPIIP is referred to as Prospective Resources; the remainder is classified as unrecoverable. The estimates for Contingent Resources, Prospective Resources, DPIIP and UPIIP are estimates only and the actual results may be greater or less than the estimates provided. There is no certainty that it will be commercially viable to produce any portion of the resources except to the extent identified as proved or probable reserves.

Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

OUTLOOK

On November 18, 2014 Strategic's Board of Directors approved a capital expenditure budget of $52 million for the first six months of 2015, focused on accelerated development and extension of the Muskeg fairway at Marlowe. The budget included a two-rig drilling program in the first quarter of 2015, drilling up to 14 wells in the first six months of the year.

Crude oil prices experienced a precipitous fall in late 2014, ending the year at US$53/bbl at WTI. In response to low commodity prices, Strategic has made several changes to its cost structure and 2015 capital spending budget to preserve financial flexibility:

- The Company prudently elected to stop the winter Muskeg drilling program in order to preserve capital. One Muskeg horizontal well (13-31) was drilled and completed in January 2015 and is currently on production.
- Strategic's revised capital expenditure budget for the first half of 2015 is $11 million.
- Approximately 700 boed of production has been shut-in by suspending operations at Bistcho, Cameron Hills and Larne, which are not economic at current commodity prices.
- The Company has reduced its office and field staff by approximately 35 percent in order to remain competitive. Staff reductions were primarily related to the suspension of operations, realignment of the management team structure and the reduction in budgeted capital spending in 2015 compared to previous years.

With the shut-in of production at Bistcho and Cameron Hills, the Company estimates that production for the first six months of 2015 will average 3,000 boed (73 percent oil). Approximately 35 percent of expected oil production for the first half of 2015 is hedged at CAD $90.15/bbl at WTI, and the Company's production is unhedged after that date.

Despite a difficult commodity price environment, Strategic has continued to experience success with its Muskeg drilling program, improving production performance and reducing drilling days and costs. The Company drilled and completed 1 Muskeg Stack horizontal well in January 2015 and completed another well drilled in December 2014 before curtailing its capital program due to low oil prices and financial constraints. These wells are currently on production and meeting the Company's internal type curve.

Strategic is committed to continue its development at Marlowe and remains focused on adjusting its cost structure to fit this current low price environment, remaining competitive, and positioning the Company for when commodity prices improve.

FOURTH QUARTER RESULTS

Fourth quarter information ($thousands, except where noted)	Three months ended December 31 **2014**	2013
Average daily production volumes		
Oil & NGL (bbl/d)	**2,694**	1,888
Natural Gas (mcf/d)	**7,382**	5,753
Total (boed)	**3,925**	2,847
Net loss		
Petroleum and natural gas sales [1]	**18,790**	15,377
Royalties	**(3,320)**	(3,126)
Unrealized gain (loss) on risk management contracts	**8,055**	(1,501)
Realized gain (loss) on risk management contracts	**1,232**	(447)
	24,757	10,303
Operating costs	**8,242**	9,046
Transportation costs [1]	**559**	953
Exploration	**399**	-
General and administrative	**2,234**	1,550
Finance costs	**966**	823
Stock-based compensation	**244**	423
Depletion, depreciation and amortization (“DD&A”)	**16,340**	6,961
Gain on disposition of PP&E	**(6)**	-
Impairment of PP&E	**114,000**	1,098
Net loss before taxes	**(118,221)**	(10,551)
Deferred tax recovery	**900**	699
Net loss	**(117,321)**	(9,852)
Net loss per common share	**(0.22)**	(0.04)
Average prices		
West Texas Intermediate (“WTI”) Oil (US$/bbl)	**73.15**	97.46
Oil & NGL price ($/bbl)	**65.67**	77.25
Natural gas price ($/mcf)	**3.70**	3.71
Oil equivalent ($/boe)	**52.04**	58.72
Funds from operations [2]	**4,974**	(320)
($/common share)	**0.01**	(0.00)
Cash flow provided by operating activities	**8,134**	2,122
($/common share)	**0.02**	0.01
Exploration and development expenditures	**24,456**	29,484

(1) In 2014, revenues are presented net of pipeline tariff charges on oil sales which occur after title to the product has passed to the customer. Prior year amounts for revenue and transportation costs have been reclassified to conform to the current period presentation.

(2) Funds from operations is a Non-IFRS measure, see “Non-IFRS Measures” in this MD&A

In comparing the fourth quarter of 2014 with the fourth quarter of 2013:

- Production increased 38 percent to 3,925 boed for the current quarter, primarily due to the Company's successful Muskeg drilling program at Marlowe. Production volumes for the current period were also positively impacted by the sale of 24,000 barrels of oil (260 bbl/d) from inventories held at September 30, 2014 which could not be sold in the third quarter as a result of a temporary shut-down of a third party sales oil pipeline. The higher production volumes drove an increase in revenue of $3.4 million or 22 percent over 2013 levels.

- Oil prices decreased 15 percent increase as a result of a 25 percent drop in WTI prices, partially offset by an increase in the CAD/US foreign exchange rate. Natural gas prices were relatively stable from period to period.

- Realized and unrealized gains on risk management contracts increased to $1.2 million and $8.0 million, respectively from losses of $0.4 million and $1.5 million in 2013 due to the decline in WTI oil prices in the last two months of 2014.

- Royalty rates decreased from 20.3 percent of revenues in 2013 to 17.7 percent of revenues in 2014, due to a higher percentage of production from new wells in the current period. Newly drilled wells in Alberta benefit from a 5 percent first year royalty rate.

- Operating costs decreased 9 percent from 2013 and 34 percent on a per boe basis, due to lower turnaround costs in the current period and significantly higher production levels. Turnaround costs for the 9-17 facility at Marlowe totaled $1.2 million for the fourth quarter of 2013, whereas no major plant turnaround was performed in 2014. Fourth quarter 2014 operating costs included $0.5 million for a well casing repair at Cameron Hills, which is not expected to recur in 2015.

- Transportation costs decreased 58 percent to $1.55 per boe from $3.64 per boe for the fourth quarter of 2013 due to the impact of the Bistcho sales pipeline, which was operational in early 2014.

- Exploration costs increased to $0.4 million from nil in 2013 as a result of impairment charges related to exploration and evaluation ("E&E") assets in southern Alberta.

- G&A expenses increased by $0.7 million due to costs related to the third party resource report, higher incentive compensation payments and lower overhead recoveries.

- Funds from (used in) operations increased to $5.0 million or $0.01 per common share from $(0.3) million or $(0.00) per share for the fourth quarter of 2013 due primarily to higher revenues and lower operating costs, partially offset by higher G&A expenses.

- DD&A expense increased by $9.4 million as a result of reserve write-downs at Maxhamish, Bistcho/Cameron Hills and Larne, which increased the DD&A expense in those areas by $6.4 million, as well as higher production levels at Marlowe. DD&A is calculated on a unit of production basis for most items of PP&E and fluctuates with production and reserves over time.

- Strategic recorded an impairment charge of $114.0 million in the fourth quarter of 2014, related to declining oil prices and deferred costs and affecting the Company's Marlowe, Bistcho/Cameron Hills and other minor oil-producing assets.

- Net loss increased to $117.3 million ($0.22 per basic and diluted common share) from $9.9 million ($0.04 per basic and diluted common share) due to impairment charges and higher DD&A expense, partially offset by increased funds from operations and unrealized gains on risk management contracts.

- Exploration and development expenditures totalled $24.5 million for the three months ended December 31, 2014 as compared to $29.5 million for the comparable quarter in 2013. Strategic has been successful in reducing drilling costs and times at Marlowe, drilling 5 wells in the current period with one rig. Other projects included road construction and lease preparation activities required to continue development of the Muskeg fairway in north Marlowe throughout 2015.

RESULTS OF OPERATIONS

Production

	Year ended December 31	
	2014	2013
Oil & NGL – bbl/d	**2,343**	2,339
Natural gas – mcf/d	**6,715**	5,588
Total daily production (boed)	**3,462**	3,270

Oil & NGL production in 2014 was consistent with 2013 levels, as new production from Muskeg drilling was offset by natural declines from existing Keg River oil production at Marlowe and Cameron Hills. Production earlier in 2014 was affected by oil volumes used to fill the Bistcho sales pipeline, facility downtime at Bistcho/Cameron Hills and a lack of new drilling activities at Marlowe as a result of financial constraints. Strategic commenced an 11-well drilling program in June 2014 which drove an increase in oil and gas volumes up to 3,925 boed for the fourth quarter of 2014.

Gas production increased 20 percent in 2014 due to associated gas production from Muskeg Stack oil drilling at Marlowe.

Average production volumes for the last six months of 2014 were 3,580 boed, 6 percent short of production guidance of 3,800 boed, as a result of production downtime on flowing Muskeg wells caused by cold weather in December, as well as a delay in receiving new well licenses early in the fourth quarter which resulted in delays in drilling and bringing new wells on production relative to the Company's forecast.

Revenue

	Year ended December 31	
($thousands, except where noted)	**2014**	2013
Sales		
Oil & NGL [2]	**71,461**	72,012
Natural gas	**11,005**	6,726
Oil and natural gas sales	**82,466**	78,738
Unrealized gain (loss) on risk management contracts	**12,217**	(8,533)
Realized gain (loss) on risk management contracts	**(6,322)**	(2,621)
Other revenue	**-**	94
	88,361	67,678
Reference prices		
WTI Oil (US$/bbl)	**93.00**	97.97
AECO daily index ($/MMBTU)	**4.48**	3.16
Average prices [1]		
Oil & NGL ($/bbl)	**83.56**	84.35
Oil & NGL, including realized risk management loss ($/bbl)	**76.66**	81.31
Natural gas ($/mcf)	**4.49**	3.30
Natural gas, including realized risk management loss ($/mcf)	**4.32**	3.30
Oil equivalent ($/boe)	**65.26**	65.97

(1) Average prices do not include unrealized losses on risk management contracts or other revenue.
(2) In 2014, revenues are presented net of pipeline tariff charges on oil sales which occur after title to the product has passed to the customer. Prior year amounts for revenue and transportation costs have been reclassified to conform to the current period presentation.

The Company's oil and natural gas sales for the year ending December 31, 2014 increased 5 percent to $82.5 million from $78.7 million in 2013, primarily driven by higher production levels and a 36 percent increase in natural gas prices.

The average price realized for oil and NGLs in 2013 decreased to $83.56 per bbl from $84.35 per bbl in 2013, as a decline in WTI oil prices was offset by a higher CAD/US foreign exchange rate. Strategic also sold its non-operated NGL production in June 2014, which received a lower price per bbl than the Company's light oil production at Marlowe and Cameron Hills. Average natural gas prices increased 36 percent to $4.49 per mcf in 2014 from $3.30 per mcf in 2013, consistent with the 41 percent increase in AECO daily index prices over the same period.

Risk Management Contracts

The Company's net income and funds from operations are exposed to fluctuations in commodity prices, interest rates and foreign exchange rates. As part of its risk management program, Strategic may enter into financial commodity price management contracts for up to 60 percent of expected production levels, depending on current commodity prices, price volatility and the size and nature of the Company's capital spending programs.

A summary of Strategic's commodity price risk management contracts as at December 31, 2014 is as follows:

Financial WTI Crude Oil Contracts

Term		Contract Type	Volume (bbl/d)	Fixed Price (CAD$/bbl)	Index
01-Jan-2015	30-Jun-2015	Swap	750	90.15	WTI - NYMEX
01-Jul-2015	31-Dec-2015	Option [1]	250	90.00	WTI - NYMEX

(1) Counterparty has an option to convert into a swap at the fixed price indicated. The option expires monthly during the contract term.

The Company recorded an unrealized gain on risk management contracts of $12.2 million for 2014, as a result of the reversal of unrealized risk management liabilities on the statement of financial position at December 31, 2013 and a significant decrease in the forward price curve for WTI oil in late 2014. Unrealized gains and losses on risk management activities do not affect Strategic's funds from operations or cash available for capital spending programs.

Royalties

	Year ended December 31	
($thousands, except where noted)	**2014**	2013
Crown royalties	**16,531**	16,536
Freehold and overriding royalties	**904**	781
Total royalties	**17,435**	17,317
Per boe	**13.80**	14.51
Percentage of oil & natural gas revenues	**21.1%**	22.0%

Royalty expense consists of royalties paid to provincial governments (including the effect of the Crown royalty initiative program), freehold land owners and overriding royalty owners. Royalty expense also includes the impact of gas cost allowance, which is the reduction of natural gas royalties payable to the Government of Alberta to recognize capital and operating expenditures incurred in the gathering and processing of its royalty share of production. Crown royalties on oil production are paid in product, which is taken in kind and marketed separately by the provincial government. Generally royalty rates in western Canada vary based on volume produced by individual wells, prices received and the area the production is derived from. Revenues from newly drilled wells benefit from a crown royalty reduction to five percent for the first year of production, up to a maximum of 500,000 Mcf of natural gas or 50,000 bbls of crude oil for a well up to 2,500 metres of total depth. The time frame and maximum production amounts are increased by six months and 100,000 Mcf or 10,000 bbls for each additional 500 metres of total depth. Strategic's wells are typically from 2,500 to 3,000 metres in total depth.

Royalties decreased in 2014 as a percentage of revenues and on a per boe basis royalties from 2013 as a result of an increasing proportion of revenues being derived from Muskeg wells drilled in 2014 and late 2013.

Royalties increased marginally to $17.4 million for year ended December 31, 2014 from $17.3 million for the period year due to higher revenues, driven primarily by higher natural gas production.

Operating and Transportation Costs

	Year ended December 31	
($thousands, except per boe amounts)	**2013**	2013
Operating costs	**32,513**	28,670
Transportation costs [1]	**3,158**	4,242
	35,671	32,912
Per boe		
Operating costs	**25.73**	24.02
Transportation costs	**2.50**	3.56
	28.23	27.58

(1) In 2014, revenues are presented net of pipeline tariff charges on oil sales which occur after title to the product has passed to the customer. Prior year amounts for revenue and transportation costs have been reclassified to conform to the current period presentation.

Operating expenses increased from $28.7 million ($24.02 per boe) in 2013 to $32.5 million ($25.73 per boe) in 2014. Of the $3.8 million increase in operating costs, $3.4 million was incurred in the first three months of the year due to a full quarter of operations at Bistcho/Cameron Hills, which was acquired on February 28, 2013, as well as additional chemicals expense and workovers at Marlowe . Strategic incurred significant costs in 2014 developing optimal pumping strategies for its Muskeg wells, and is currently experiencing improved runtime and production rates as a result of these efforts. As such the Company anticipates that workover charges will decrease in 2015 from 2014 levels.

Transportation costs decreased to $3.2 million ($2.50 per boe) from $4.2 million ($3.56 per boe), primarily due to Bistcho sales oil pipeline, which was constructed in the first quarter of 2014 and connects oil production from the Marlowe area to the Rainbow oil sales pipeline at Zama. This resulted in a significant reduction in oil trucking costs at Marlowe.

Operating Netbacks

	Year ended December 31	
($ per boe)	**2014**	2013
Revenues [1]	**65.26**	65.97
Royalties	**13.80**	14.51
Operating costs	**25.73**	24.02
Transportation costs [1]	**2.50**	3.56
Netback per boe	**23.23**	23.88

(1) In 2014, revenues are presented net of pipeline tariff charges on oil sales which occur after title to the product has passed to the customer. Prior year amounts for revenue and transportation costs have been reclassified to conform to the current period presentation.

Strategic's operating netback decreased 3 percent to $23.23 per boe in 2014 from $23.88 per boe for 2013. The Company succeeded in reducing its royalty rate by increasing production from newly drilled wells, but unit operating costs increased due to a full year of operations at Bistcho/Cameron Hills and higher workover and chemicals costs at Marlowe. The majority of the increase in operating costs was incurred in the first quarter of 2014 and related to a full quarter of winter operations at Bistcho/Cameron Hills and a surface casing vent flow repair at Marlowe. The Company has been focused on building cost efficiencies in field operations and reduced operating costs in the fourth quarter of 2014 by $0.8 million from 2013 levels.

Strategic's 100 percent owned and operated focus area is Marlowe, which continued to generate competitive netbacks in 2014. With the shut-down of Bistcho/Cameron Hills in February 2015, corporate netbacks are expected to be similar to the netback at Marlowe, where operating costs were $15 per boe in the fourth quarter of 2014 as sales volumes increased. The breakdown of Strategic's operating netback by area for 2014 is as follows:

Operating netback ($/boe)	Marlowe	Bistcho/Cameron Hills	Other	Total
Revenue	72.36	40.92	63.65	**65.26**
Royalties	(17.82)	(2.08)	(3.48)	**(13.80)**
Operating costs	(19.84)	(40.47)	(51.65)	**(25.73)**
Transportation costs	(2.63)	(2.36)	(1.13)	**(2.50)**
Operating netback	32.07	(3.99)	7.39	**23.23**

Exploration and Evaluation Expense

The Company's E&E expense represents all pre-license costs and capitalized exploration and evaluation costs that have been subsequently expensed due to a lack of technical feasibility and commercial viability. For the year ended December 31, 2014, the Company recorded $0.4 million of E&E expense compared to $nil for the prior year. Current period expenses related to seismic costs incurred in southern Alberta and the Zama area.

General and Administrative Expenses

	Year ended December 31	
($thousands, except per boe amounts)	**2014**	2013
Gross general and administrative expenses	**10,145**	9,420
Overhead recoveries	**(978)**	(972)
Capitalized G&A	**(1,774)**	(2,248)
Net general and administrative expenses	**7,393**	6,200
Per boe	**5.85**	5.19

General and administrative ("G&A") expenses reflect all head office costs, a portion of which are charged to operated wells and facilities through overhead recoveries. Costs related to technical office staff that are directly involved in the Company's capital spending programs are capitalized to PP&E. Net G&A expenses increased to $7.4 million ($5.85 per boe) for 2014 from $6.2 million ($5.19 per boe) in 2013 as a result of increased office staff to manage the Muskeg drilling program and increasing production base at Marlowe and higher incentive compensation payments, partially offset by lower legal and consulting expenses. Capitalized G&A was also lower in 2014 compared to 2013 due to lower capital expenditures.

Finance Expense

	Year ended December 31	
($thousands, except per boe amounts)	**2014**	2013
Interest expense	**3,375**	2,540
Accretion expense	**1,188**	869
Total	**4,563**	3,409
Per boe	**3.61**	2.86

Interest expense increased to $3.4 million for 2014 from $2.5 million for 2013 due to higher average interest rates on the bank credit facility during the year, as well as interest expense paid on a short-term promissory note to a director of the Company. Accretion expense increased by $0.3 million in 2014 due to the increase in cost estimates for Strategic's decommissioning liabilities.

Stock Based Compensation

Stock based compensation is a non-cash charge which reflects the estimated value of stock options granted. The Company uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants. The fair value of all stock options granted is recorded as a charge to net loss over the period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes options pricing model.

During the year ended December 31, 2014 the Company recorded $1.0 million in stock based compensation expense as compared to $1.7 million recorded in the previous year. Black-Scholes values of the Company's stock options have decreased in line with the decrease in share price over the past year, leading to lower stock-based compensation expense.

Depletion, Depreciation and Amortization

	Year ended December 31	
($thousands, except per boe amounts)	**2014**	2013
Depreciation, depletion, and amortization	**42,011**	28,033
Per boe	**33.25**	23.49

Depletion, depreciation and amortization ("DD&A") is computed individually for each producing area on a unit of production basis, using proved and probable reserves and including future development expenditures in the cost base subject to depletion. DD&A expense for the year ended December 31, 2014 increased by 50 percent to $42.0 million compared to $28.0 million for 2013, and increased by 42 percent on a boe basis, as a result of significant capital spending on facilities over the past two years, as well as reserve writedowns at Bistcho/Cameron Hills and Maxhamish, which resulted in depletion charges for these assets of $6.9 million in the fourth quarter of 2014 compared to $0.5 million for the corresponding period in 2013.

Impairment Loss

Impairment testing is required when there are indicators of impairment such as a significant drop in commodity prices or a downward revision of proved and probable oil and gas reserves. When indicators of impairment exist, impairment testing is performed at the cash generating unit ("CGU") level and is a point in time process for testing and measuring a potential impairment of assets, whereby the carrying value of each CGU is compared to the CGU's recoverable amount, which is the greater of its value in use and its fair value less costs to sell. The Company's development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. At December 31, 2014, the Company identified indicators of impairment for the Marlowe, Bistcho/Cameron Hills and other Canadian CGUs based on a precipitous decline in oil prices in the fourth quarter and decreases in recognized reserves in certain areas from 2013 levels.

The recoverable amount was determined based on the fair value less costs to sell method for reserves as well as resources estimated by management to be realized based on planned future drilling locations not considered in the reserve report. The key assumptions used in determining the recoverable amount include the future cash flows using reserve and resource forecasts, forecasted commodity prices, discount rates, inflation rates and future development costs estimated for reserves by independent reserve engineers and by internal estimates based on historical experiences and trends for planned future drilling locations.

The values assigned to the future cash flows, forecasted commodity prices and future development costs were obtained from Strategic's year-end reserve report, which was evaluated or audited by its independent reserve engineers. The commodity prices used for 2015 were the prices used for the Company's revised budget released in February 2015. These values were based on future cash flows of proved plus probable reserves discounted at a pre-tax rate of 10 percent (2013 – 10 percent). The future cash flows also consider, when appropriate, past capital activities, observable market conditions, comparable transactions and future development costs primarily based on anticipated development capital programs.

The value of resources incremental to the reserve report was obtained from internal analysis completed by management most notably through the review of its drilling program results and future drilling plans outlined in its current five-year plan. This was further supported by contingent and prospective resource studies that were compiled by independent reserve engineers. Based on this internal analysis, Strategic identified and risked potential drilling locations that were not assigned any proved plus probable reserves. The value of these additional drilling locations was included in the recoverable amount, based on the net present value of proved undeveloped locations within the same resource play from the Company's most recent annual reserve report. A discount rate of 10 percent and risk factors of 50 to 75 percent were applied to determine an estimate of the present value of the future cash flows from these future drilling locations.

For the year ended December 31, 2014, the Company recognized an impairment charge of $114.0 million, including $97.1 million related to Marlowe, $14.8 million related to Bistcho/Cameron Hills and $2.1 million related to the Other Canadian CGU, compared to $1.1 million in 2013 related to the other Canadian CGU. Impairment at Marlowe was primarily related to the decline in oil prices as well as a $5.0 million charge for deferred costs related to environmental liabilities, while impairment charges in other CGUs were caused by commodity price declines and decreases in reserves from the previous year-end.

Deferred Taxes

Strategic recorded a deferred tax recovery of $2.3 million for the year ended December 31, 2014 compared to $0.7 million for 2013. The Company had issued $17.0 million of flow-through common shares in October 2013, with a related price premium of $2.3 million recorded on the balance sheet on the issue date. As eligible flow-through expenditures were incurred by the Company, the price premium was reduced and a deferred tax recovery was recorded. Strategic issued an additional $9.5 million in flow-through shares in September and October 2014, with a related price premium of $0.7 million. Strategic fulfilled all of its flow-through commitments prior to year-end, and therefore the deferred price premium on the balance sheet at December 31, 2014 was $nil.

Funds From Operations and Net Loss

	Year ended December 31	
($thousands, except per share amounts)	**2014**	2013
Funds from operations	**12,270**	17,162
Per share – basic & diluted	**0.03**	0.08
Cash provided by operating activities	**13,396**	18,493
Per share - basic & diluted	**0.04**	0.08
Net loss	**(129,490)**	(22,316)
Per share – basic & diluted	**(0.34)**	(0.10)

Funds from operations and cash provided by operating activities decreased 29 percent to $12.3 million and $13.4 million, respectively for 2014 from $17.2 million and $18.5 million in 2013 as an increase in revenues due to rising production levels was more than offset by an increase in the realized loss on risk management contracts and higher operating costs. The majority of the increase in operating costs was incurred in the first quarter of 2014 and related to a full quarter of winter operations at Bistcho/Cameron Hills and a surface casing vent flow repair at Marlowe.

For the year ended December 31, 2014, the Company recorded a net loss of $129.5 million ($0.34 per basic and diluted common share) compared to a net loss of $22.3 million ($0.10 per basic and diluted common share) in the prior year. The higher net loss in 2014 is a result of impairment charges and higher DD&A expense, partially offset by an unrealized gain on risk management contracts of $12.2 million.

Capital Expenditures

($thousands)	Year ended December 31 2014	2013
Drilling, completions and equipping	**68,467**	72,746
Pipelines and facilities	**29,881**	39,230
Other	**66**	248
	98,414	112,224
Net acquisitions (dispositions)	**(3,828)**	10,011
Total property, plant and equipment	**94,586**	122,235
Exploration and evaluations	**2,905**	6,927
Total net capital expenditures	**97,491**	129,162

Drilling, completions, equipping and facilities expenditures decreased to $98.4 million in 2014 from $112.2 million in 2013. Strategic achieved a 6 percent reduction in drilling, completions and equipping expenditures despite drilling 14 wells in 2014 compared to 12 wells in 2013, as Muskeg drilling cost efficiencies were identified and implemented over the last year. Average drilling days per well were reduced from 29 days in the first quarter of 2014 to 14 days for the last two wells in the Muskeg program.

Facility projects in 2014 included the construction of the Bistcho sales oil pipeline to connect Marlowe oil production to the Rainbow sales pipeline at Zama in northern Alberta, as well as a pipeline from West Marlowe to one of the Company's oil processing facilities and major plant turnarounds at Bistcho/Cameron Hills. Prior year projects included a major expansion of the Marlowe oil processing facility at 9-17, installation of water disposal facilities, and a pipeline connecting the 9-17 and 1-28 plants. Going forward the Company has processing capacity at Marlowe of 8,000 bbl/d of oil, 18,000 bbl/d of total fluid and 40 MMcf/d of natural gas, and will be able to devote the vast majority of its capital spending towards drilling and completion activities at Marlowe.

Dispositions include the sale of minor gas-weighted assets in central Alberta for $3.4 million in June 2014, as well as the sale of an interest in a wellbore to a related party for $0.3 million.

Exploration and evaluation ("E&E") costs are area expenditures where technical feasibility and commercial viability has not yet been determined. E&E costs decreased to $2.9 million in 2014 from $6.9 million in 2013 due to lower seismic spending. In 2013 2D and 3D seismic programs were conducted at Marlowe.

Decommissioning Liabilities

Decommissioning liabilities increased to $54.9 million at December 31, 2014 from $35.9 million at December 31, 2013, and accretion expense increased accordingly, as a result of a soil remediation estimate for a prior year pipeline spill at Marlowe, an increase in estimates for pipeline reclamation liabilities and a lower discount rate. As the pipeline spill was claimed under the Company's insurance coverage, a receivable of $3.7 million has been recorded representing the estimated cost of remediation work completed in 2015 and ongoing monitoring costs, of which $2.9 million is included in current assets.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended ($thousands, except where noted)	**Dec 31, 2014**	Sept 30, 2014	Jun 30, 2014	Mar 31, 2014
Oil and natural gas sales	**18,790**	19,394	23,373	20,908
Net income (loss)	**(117,321)**	213	(2,717)	(9,664)
Net income (loss) per share – basic	**(0.22)**	0.00	(0.01)	(0.04)
Net income (loss) per share – diluted	**(0.22)**	0.00	(0.01)	(0.04)
Average daily production (boed)	**3,925**	3,234	3,538	3,147
Average realized price ($/boe)	**52.04**	65.18	72.61	73.82

Quarter ended ($thousands, except where noted)	Dec 31, 2013	Sept 30, 2013	Jun 30, 2013	Mar 31, 2013
Oil and natural gas sales	15,377	22,353	23,459	17,546
Net loss	(9,852)	(6,759)	(2,338)	(3,371)
Net loss per share – basic	(0.04)	(0.03)	(0.01)	(0.02)
Net loss per share – diluted	(0.04)	(0.03)	(0.01)	(0.02)
Average daily production (boed)	2,847	3,510	3,924	2,797
Average realized price ($/boe)	58.72	69.22	65.70	69.70

Oil and natural gas sales are a function of average daily production levels, the oil/gas production mix and commodity prices, and were highest in the second quarter of 2013 and the second quarter of 2014, due to increased production and a higher realized price, respectively. Sales were lowest in the fourth quarter of 2013 as production volumes were impacted by facility downtime and extremely cold weather in December.

Net income (loss) varies with sales and funds from operations, as well as non-cash expenses incurred such as unrealized losses and gains on risk management contracts, DD&A and impairment. Net loss was highest in the fourth quarter of 2014 due to higher DD&A expenses and impairment charges of $114.0 million. The net loss was low in the second quarter of 2013 due to higher funds from operations relative to the other quarters presented, and in the second quarter of 2014 due to a gain on disposal of property of $2.0 million. The Company realized net income of $0.2 million for the three months ended September 30, 2014 due to a realized gain on risk management contracts of $6.8 million.

LIQUIDITY AND CAPITAL RESOURCES

The Company considers its capital structure to include shareholders' equity and working capital, including bank debt. The objectives of the Company are to maintain a strong balance sheet affording the Company financial flexibility to achieve goals of continued growth and access to capital. In order to maintain or adjust the capital structure, the Company may issue new common shares, issue or repay debt, or adjust exploration and development capital expenditures.

The Company monitors its capital structure based on net debt and adjusted working capital (deficiency), as calculated below:

($thousands)	**December 31, 2014**	December 31, 2013
Current assets, excluding risk management contracts	**11,439**	9,685
Accounts payable and accruals	**(26,815)**	(28,457)
Current decommissioning liabilities	**(4,007)**	-
Adjusted working capital (deficiency)	**(19,383)**	(18,772)
Bank indebtedness	**(29,016)**	(63,775)
Net debt	**(48,399)**	(82,547)

At December 31, 2014 the Company had an $80 million credit facility (the "Facility") with a Canadian chartered bank. Subsequent to the reporting period, the Facility was adjusted to $60 million, comprised of a $40 million revolving operating loan, with the balance being a non-revolving facility that will be reduced at a rate of $0.5 million per month starting April 1, 2015. Amounts outstanding under the Facility are repayable on demand, and bear interest at a rate of 0.5% to 2.5% over the bank's prime lending rate for prime loans, or at bankers' acceptance rates plus a stamping fee ranging from 1.75% to 3.75%, depending on Strategic's debt to cash flow ratio. Amounts due under the non-revolving loan bear interest at 2.0% above the interest rates on the operating loan. In addition to $29.0 million drawn at December 31, 2014, the Company has $4.4 million letters of credit outstanding with third parties which reduce the amount of funds available under the Facility.

The Facility is secured by a general security agreement including fixed and floating charges on all property, plant and equipment. The loan agreement contains a financial covenant that requires the Company to maintain an adjusted working capital ratio of not less than 1:1, but for the purpose of the calculation the unused portion of the revolving operating line is included in current assets and, the current portion of debt and risk management liabilities are both excluded from current liabilities. At December 31, 2014, the Company was in compliance with all financial covenants. The Company anticipates being in violation of the working capital covenant of its credit facility as at March 31, 2015 as a result of capital expenditures related to the Muskeg drilling program and reduced cash flows due to low commodity prices for the first quarter of 2015 (see "Going concern" in this MD&A). The Facility has a renewal date of May 1, 2015.

The Company has a working capital deficiency at December 31, 2014 and 2013 as capital spending has exceeded cash flows for both periods. In addition, invoices related to capital spending and operating costs are typically paid on 60 to 90 day terms, whereas receivables related to oil and gas production are collected after 25 days, per normal industry terms.

In light of the reduction in the Company's credit facility and low commodity prices, Strategic has curtailed the winter drilling program and reduced planned capital expenditures in the first half of 2015 to $11 million. Future capital expenditure programs will be dependent on obtaining additional financing, a joint venture or a sale of assets as funds from operations will be diverted towards repayment of the non-revolving portion of the Company's credit facility.

SHARE CAPITAL

	Year ended December 31	
	2014	2013
Weighted average common shares outstanding (thousands)		
Basic	**381,240**	217,604
Diluted	**381,240**	217,604

	December 31, 2014	December 31, 2013
Outstanding securities (thousands)		
Common shares	**542,319**	260,601
Stock options	**15,313**	13,235

On March 31, 2014, the Company issued 100.0 million common shares via a private placement at a price of $0.50 per common share for gross proceeds of $50.0 million (net proceeds of $49.3 million after transaction costs). Of the $50.0 million gross proceeds, $40.0 million (80.0 million common shares) were acquired by entities controlled by a director of the Company and another $0.29 million (0.6 million common shares) were acquired by directors and officers of the Company. Proceeds from the private placement were primarily used to repay accounts payable and accrued liabilities incurred in executing the first quarter 2014 capital program.

The Company also completed a $73 million private placement of common shares in 2014, closing the first tranche on September 30, 2014 and the second tranche on October 15, 2014. Strategic issued a total of 159.7 million common shares priced at $0.40 per share and 21.6 million shares issued on a flow-through basis pursuant to the Income Tax Act (Canada) at $0.44 per share, for gross proceeds of $73.4 million ($73.0 million after transaction costs). As part of the private placement, 132.5 million common shares ($53.0 million) were acquired by entities controlled by a director of the Company, and another 7.1 million common shares ($2.7 million) were acquired by directors and officers of the Company. Proceeds from the private placement were used to fund Strategic's capital programs for the second half of 2014, reduce bank indebtedness and repay a U.S. $10 million promissory note outstanding to an entity controlled by a director.

For the year ended December 31, 2014, 6.6 million stock options were granted at an average price of $0.42 per common share, and 400,000 stock options were exercised for common shares of the Company for total proceeds of $0.14 million.

As of March 15, 2015 there were 542,318,629 common shares outstanding and 14,855,000 stock options outstanding.

SUMMARY OF ANNUAL INFORMATION

	Year ended December 31		
($000, except per share amounts)	**2014**	2013	2012
Total revenue	**82,466**	78,738	56,512
Net income (loss)	**(129,490)**	(22,316)	(4,788)
Per common share basic)	**(0.34)**	(0.10)	(0.03)
Per common share (diluted)	**(0.34)**	(0.10)	(0.03)
Total assets	**239,601**	274,221	159,718
Total long-term liabilities	**50,904**	37,413	18,773

Net revenues have increased over the past three years as a result of production additions from successful capital programs, primarily at Marlowe, and through the acquisition of Bistcho/Cameron Hills in February 2013. Net loss was lowest in 2012 due to lower DD&A expense, finance costs and impairment charges compared to 2013 and 2014. The loss in 2014 was affected by an impairment charge of $114.0 million related to a significant decline in oil prices. Total assets have increased in 2013 due to capital spending and acquisitions exceeding DD&A expense, and decreased in 2014 due to asset impairment charges. Long-term liabilities consist primarily of decommissioning obligations, and have increased over the two-year period as the Company's oil and gas asset base has also increased.

TRANSACTIONS WITH RELATED PARTIES

Legal fees in the amount of $0.37 million (2013 - $0.45 million) were incurred to a legal firm of which a director is a partner, and are included as general and administrative expenses or share issue costs. Software charges of $0.20 million (2013 - $0.20 million) were incurred to a software firm which is controlled by an officer of the Company. Accounts payable and accrued liabilities at 2014 include $0.09 million (2013 - $0.31 million) due to related parties. The above transactions were conducted in the normal course of operations and were recorded at exchange amounts which were agreed upon between the Company and the related parties. Transaction amounts reflect fair values.

Entities controlled by directors of the Company and directors and officers of the Company have also participated in share offerings in 2014 as discussed in this MD&A.

COMMITMENTS

The Company has lease agreements for office space, office equipment and natural gas transportation resulting in the following commitments:

Year	**Office ($000)**	**Gas transportation ($000)**
2015	$ 311	$ 452
2016	10	416
2017	-	388
2018	-	282
	$ 321	$ 1,538

SENSITIVITY ANALYSIS

The following table analyses the Company's sensitivity of funds from operations to changes in commodity prices and interest rates:

	For the year ended December 31	
($000)	**2014**	2013
$1.00 increase in oil price	**659**	687
$0.25 increase in gas price	**487**	399
1% increase in interest rate	**464**	489

FUTURE ACCOUNTING PRONOUNCEMENTS

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. IFRS 15 will be applied by the Company on January 1, 2017 and the Company is currently evaluating the impact of the standard on its financial statements.

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied by the Company on January 1, 2018 and the Company is currently evaluating the impact of the standard on its financial statements.

CHANGES IN ACCOUNTING POLICIES

As of January 1, 2014, the Company adopted several new IFRS standards and amendments in accordance with the transitional provisions of each standard. A brief description of each new standard and its impact on the Company's consolidated financial statements follows below:

IAS 36 "Impairment of Assets"
This standard has been amended to reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The retrospective adoption of these amendments impact the Company's disclosures in the notes to the consolidated financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 39 "Financial Instruments: Recognition and Measurement"
This standard has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on the Company's consolidated financial statements.

IFRIC 21 "Levies"
This standard was developed by the IFRS Interpretations Committee ("IFRIC") and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this interpretation does not have any impact on the Company's financial statements.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in *Note 3* to the consolidated financial statements. These accounting policies are subject to estimates and key judgments about future events, many of which are beyond the Company's control. The following is a discussion of the accounting policies that are critical to the financial statements.

Reserves Estimates

The Company retained McDaniel to evaluate its crude oil and natural gas reserves, prepare an evaluation report, and report to the Company. The process of estimating crude oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting crude oil and natural gas prices and costs change. Reserves can be classified as prove, probable or possible with decreasing levels of likelihood that the reserve will be ultimately produced.

Reserve estimates are a key input to the Company's depletion calculations and impairment tests. Property, plant and equipment within each area are depleted using the unit-of-production method based on proved plus probable reserves using estimated future prices and costs. In addition, the costs subject to depletion include an estimate of future costs to be incurred in developing proved reserves. A revision in reserve estimates or future development costs could result in the recognition of higher depletion charged to net income.

E&E Costs

Capitalized costs that are exploratory in nature such as undeveloped land acquisitions, seismic expenditures and exploration drilling are included in E&E costs. Costs are transferred from E&E to property, plant and equipment once technical feasibility and commercial viability of the underlying resource have been established. The results of a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Impairment

Under IFRS, the carrying amount of property, plant and equipment and E&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. Management's judgement is required to perform such reviews. If there are indications of impairment, carrying values of assets are compared to related recoverable amounts. Reserves, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the recoverable amount. Revisions of these estimates could result in significant changes to impairment charges recorded in a reporting period, as well as the carrying value of the Company's assets.

Decommissioning Liabilities

Decommissioning liabilities are measured based on the estimated costs of decommissioning and estimated timing to reclamation, discounted to their net present value using a credit-adjusted risk-free rate. Decommissioning liabilities are reassessed at each reporting date, and these estimates may change.

By nature of its oil and gas operations in Northern Alberta, the Company is subject to numerous safety and environmental regulations, with which non-compliance may result in adverse financial impact. The Company mitigates these risks through the adherence to formal safety and environmental policies, as well as adequate insurance coverage. The Company is currently remediating an environmental spill at Marlowe and is subject to a claim from the Occupational, Health and Safety division of the Government of Alberta. While the Company believes it has recorded its best estimate of the impact of these contingencies in these financial statements, the ultimate outcome of these incidents is uncertain.

Business Combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss.

Risk Management Contracts

Estimated fair values of financial instruments are subject to fluctuation depending upon the underlying commodity prices, interest rates, volatility curves and the risk of non-performance.

Stock Based Compensation

Stock based compensation expense is based on estimated fair values of stock options as of the grant date, which are calculated using a Black-Scholes option pricing model and involves assumptions such as volatility, expected option life and expected dividend yield.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates including estimates of revenue, royalties and operating costs at a specific report date, but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in process or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

BUSINESS RISKS

There are numerous risks facing participants in the oil and gas industry. Some of the risks are common to all businesses while others are specific to a sector. While Strategic realizes that these risks cannot be eliminated, it is committed to monitoring and mitigating these risks. The following reviews the general and specific risks to which the Company is exposed.

Acquisition and Development of Additional Reserves

The Company's future success is dependent upon its ability to develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive prices. Except to the extent that the Company conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well or of its ongoing operational costs.

Exploration and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing activities in areas in which the Company has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling might, where appropriate, be used by the Company to improve its ability to find, develop and produce oil and natural gas. However, notwithstanding this, the combination of technology, knowledge and skilled people may not eliminate these risks.

Acquisitions of resource issuers and resource assets by the Company will be based on engineering and economic assessments made by management. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Company. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Company's common shares. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated.

Resource Estimates

In general, estimates of gross original resources and recoverable resources are based upon a number of factors and assumptions made as of the date on which the estimates were determined, such as geological, technological and engineering estimates and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those anticipated in forward-looking estimates.

These risks and uncertainties include but are not limited to: (1) the fact that there is no certainty that the zones of interest will exist to the extent estimated or that the zones will be found to have oil with characteristics that meet or exceed the minimum criteria in terms of net pay thickness, porosity or oil saturation, or that the oil will be commercially recoverable to the extent estimated; (2) the lack of additional financing to fund the Corporation's exploration activities and continued operations; (3) fluctuations in foreign exchange and interest rates; (4) the number of competitors in the oil and gas industry with greater technical, financial and operations resources and staff; (5) fluctuations in world prices and markets for oil and gas due to domestic, international, political, social, economic and environmental factors beyond the Corporation's control; (6) changes in government regulations affecting oil and gas operations and the high compliance cost with respect to governmental regulations; (7) potential liabilities for pollution or hazards against which the Corporation cannot adequately insure or which the Corporation may elect not to insure; (8) the Corporation's ability to hire and retain qualified employees and consultants; (9) contingencies affecting the classification as reserves versus resources which relate to the following issues as detailed in the COGEH: ownership considerations, drilling requirements, testing requirements, regulatory considerations, infrastructure and market considerations, timing of production and development, and economic requirements; (10) the fact that there is no certainty that any portion of contingent resources will be commercially viable to produce; (11) the fact that there is no certainty that any portion of the prospective resources will be discovered and if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources; and (12) other factors beyond the Corporation's control. Any reference in this MD&A to DPIIP, UPIIP, contingent resources and prospective resources are not, and should not be confused with oil and gas reserves.

Oil and Natural Gas Prices and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control. The Company's ability to market its natural gas and oil may depend upon its ability to acquire space on pipelines that deliver natural gas and oil to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas which are volatile and subject to fluctuations. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Petroleum prices have fallen precipitously over the last 4 months due to global oversupply, caused primarily by growth in North American oil production and lack of a voluntary production curtailment by the Organization of Petroleum Exporting Countries ("OPEC"). Continued low commodity prices may have an adverse effect on the Company's cash flows, reserves values and capital resources, including the availability of its credit facilities.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the global economy, OPEC actions, instability in the Middle East and the impact of emerging countries such as China and India on the demand for crude oil and natural gas.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Substantial Capital Requirements and Liquidity

The Company anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. The Company's credit facilities are fully utilized and cash flows are being adversely affected by low commodity prices. As such, the Company's ability to expend the capital necessary to undertake or complete future drilling programs in order to replace reserves and maintain production will be limited without additional financing. There can be no assurance that debt or equity financing will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Moreover, the Company anticipates being in violation of its debt covenants at March 31, 2015, and its credit facility will be reduced by $0.5 million per month starting April 1, 2015. In order to address the violation and fund future capital programs Strategic may be required to alter its capitalization significantly, or obtain alternative financing at a higher cost or with more restrictive terms than the Company's existing credit facility. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards that may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Company and possibly liability to fourth parties. The oil and natural gas industry is subject to extensive environmental regulation that provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations, and such regulations may be expanded to include regulation of, among other things, emissions of carbon dioxide. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. The Company carries insurance to mitigate the cost of remediating damage from environmental incidents, but there can be no assurance that the insurance will cover all types of incidents or that remediation costs will not exceed the limit of the insurance carried. In addition, the Company will make reasonable provisions for well abandonment, facility decommissioning and site remediation where appropriate, however there can be no assurance that such provisions will be sufficient to satisfy all such obligations.

Permits and Licenses

Strategic's operations may require licenses and permits from various governmental authorities. There can be no assurance that Strategic will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Reliance on Operators and Key Employees

To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Company will be largely dependent upon the performance of its management and key employees. The Company does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Company. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of the business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of Strategic's management.

Third Party Credit Risk

The Company is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, operators of facilities, pipelines, terminals and other infrastructure used by Strategic and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Strategic which could result in a reduction of the revenue received by the Company.

Competition

Strategic competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company also competes with other companies for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Company endeavors to be competitive by maintaining a strong financial condition, by attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities.

FORWARD-LOOKING STATEMENTS

This report includes certain information, with management's assessment of Strategic's future plans and operations, and contains forward-looking statements which may include some or all of the following: (i) forecasted capital expenditures and plans; (ii) exploration, drilling and development plans, (iii) prospects and drilling inventory and locations; (iv) anticipated production rates; (v) expected violations of credit facility covenants; (vi) anticipated production and service costs; (vii) incremental development opportunities; (viii) total shareholder return; (ix) anticipated compliance with credit facility covenants; (x) asset disposition plans; (xi) potential sources of funding, which are provided to allow investors to better understand Strategic's business. By their nature, forward-looking statements are subject to numerous risks and uncertainties; some of which are beyond Strategic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental tax and royalty legislation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources, and other risks and uncertainties described under the heading 'Risk Factors' and elsewhere in the Company's Annual Information Form for the year ended December 31, 2014 and other documents filed with Canadian provincial securities authorities and are available to the public at www.sedar.com. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The principal assumptions Strategic has made includes security of land interests; drilling cost stability; royalty rate stability; oil and gas prices to remain in their current range; finance and debt markets continuing to be receptive to financing the Company and industry standard rates of geologic and operational success. Strategic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements or if any of them do so, what benefits that Strategic will derive there from. Strategic disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.