Strategic
OIL & GAS LTD.

Consolidated Financial Statements

For the years ended December 31, 2013 and 2012

Management's Report

Management's Responsibility on Consolidated Financial Statements

Management is responsible for the preparation of the accompanying consolidated financial statements. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In Management's opinion, the consolidated financial statements are in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, have been prepared within acceptable limits of materiality, and have utilized supportable, reasonable estimates.

To ensure the integrity of our consolidated financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer and chief financial officer.

The Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit Committee. The Audit Committee is composed of a majority of independent directors, all with financial expertise. The Audit Committee meets regularly with Management and the external auditors to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors and reviews their fees.

Deloitte LLP ("Deloitte"), an independent firm of chartered accountants, was to audit the consolidated financial statements of the Corporation and to provide an independent professional opinion. Deloitte's audit opinion is attached to these consolidated financial statements.

"Signed"

Gurpreet Sawhney, President & Chief Executive Officer

"Signed"

Aaron Thompson, Chief Financial Officer

March 31, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Strategic Oil & Gas Ltd.:

We have audited the accompanying consolidated financial statements of Strategic Oil & Gas Ltd. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012 and the consolidated statements of loss and comprehensive loss, consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years ended December 31, 2013 and December 31, 2012, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Strategic Oil & Gas Ltd. and its subsidiaries as at December 31, 2013 and December 31, 2012, and its financial performance and its cash flows for the years ended December 31, 2013 and December 31, 2012, in accordance with International Financial Reporting Standards.

(Signed) "Deloitte LLP"

Chartered Accountants

March 31, 2014
Calgary, Canada

Strategic Oil & Gas Ltd.

Consolidated balance sheets

(CDN$000)	Note	December 31, 2013	December 31, 2012
Assets			
Current assets			
Cash and cash equivalents		**$ 226**	$ 2,510
Inventory		**379**	179
Trade and other receivables		**9,080**	8,972
		9,685	11,661
Property, plant, and equipment, net	4,6	**249,841**	136,928
Exploration and evaluation assets	5	**14,695**	11,129
Total Assets		**$ 274,221**	$ 159,718
Liabilities			
Current Liabilities:			
Accounts payable and accrued liabilities		**$ 28,457**	$ 24,576
Bank indebtedness	9	**63,775**	34,125
Deferred price premium on flow-through shares	8	**1,619**	-
Decommissioning liabilities	10	**-**	263
Risk management contracts	17	**7,276**	224
		$ 101,127	$ 59,188
Long term Liabilities:			
Risk management contracts	17	**1,481**	-
Decommissioning liabilities	4,10	**35,932**	18,773
Total Liabilities		**$ 138,540**	$ 77,961
Shareholders' Equity			
Share capital	11	**197,970**	122,999
Contributed surplus		**9,227**	7,958
Deficit		**(71,516)**	(49,200)
		$ 135,681	$ 81,757
Total Liabilities and Shareholders' Equity		**$ 274,221**	$ 159,718

See accompanying notes to the consolidated financial statements

Commitments (Note 20)
Subsequent events (Note 21)

Approved by the Board of Directors

Signed: *"Thomas Claugus"* Signed: *"Rodger Hawkins"*

Strategic Oil & Gas Ltd.

Consolidated statements of loss and comprehensive loss

Year ended December 31 **(CDN$000, except per share amounts)**	**Note**		**2013**		2012
Revenue					
Petroleum and natural gas sales		**$**	**79,945**	$	56,512
Royalties			**(17,317)**		(9,677)
			62,628		46,835
Unrealized loss on risk management contracts			**(8,533)**		(224)
Net realized loss on risk management contracts			**(2,621)**		-
Other income			**94**		370
Revenues		**$**	**51,568**	$	46,981
Expenses					
Operating costs		**$**	**28,670**	$	13,581
Transportation			**5,449**		5,774
Exploration expenses	5		**-**		30
General and administrative			**6,200**		7,434
Finance costs	13		**3,409**		430
Stock-based compensation	12		**1,724**		1,935
Depletion, depreciation and amortization			**28,033**		20,837
Impairment of property, plant and equipment	7		**1,098**		4,023
		$	**74,583**	$	54,044
Operating loss before taxes		**$**	**(23,015)**	$	(7,063)
Deferred tax recovery	14		**699**		2,275
Net loss and comprehensive loss		**$**	**(22,316)**	$	(4,788)
Net loss per weighted average share					
Basic		**$**	**(0.10)**	$	(0.03)
Diluted		**$**	**(0.10)**	$	(0.03)
Weighted average shares outstanding - Basic	11(c)		**217,603,874**		186,800,318
Weighted average shares outstanding - Diluted	11(c)		**217,603,874**		186,800,318

See accompanying notes to the consolidated financial statements
Certain comparative figures have been reclassified to conform to the current year's presentation.

Strategic Oil & Gas Ltd.

Consolidated statements of changes in shareholders' equity

For the years ended December 31, 2013 and 2012

(CDN$000)	Note	Share Capital	Contributed Surplus	Deficit	Total equity
Balance Jan 1, 2013		**$ 122,999**	**$ 7,958**	**$ (49,200)**	**$ 81,757**
Shares issued	11(b)	76,687	-	-	76,687
Share issue costs	11(b)	(2,848)	-	-	(2,848)
Stock options exercised	11(b)	1,132	(455)	-	677
Stock-based compensation	12	-	1,724	-	1,724
Net loss		-	-	(22,316)	(22,316)
Balance December 31, 2013		**$ 197,970**	**$ 9,227**	**$ (71,516)**	**$ 135,681**

(CDN$000)	Note	Share Capital	Contributed Surplus	Deficit	Total equity
Balance Jan 1, 2012		**$ 122,973**	**$ 6,310**	**$ (44,294)**	**$ 84,989**
Share issue costs	11(b)	(14)	-	-	(14)
Share repurchases	11(b)	(632)	-	(118)	(750)
Stock options exercised	11(b)	672	(287)	-	385
Stock-based compensation	12	-	1,935	-	1,935
Net loss		-	-	(4,788)	(4,788)
Balance December 31, 2012		**$ 122,999**	**$ 7,958**	**$ (49,200)**	**$ 81,757**

See accompanying notes to the consolidated financial statements

Strategic Oil & Gas Ltd.

Consolidated statements of cash flows

Year Ended December 31 **(CDN$000)**	**Note**		**2013**		2012
Operating activities:					
Net loss for the year		**$**	**(22,316)**	$	(4,788)
Non-cash items:					
Depletion, depreciation, and amortization			**28,033**		20,838
Accretion of decommissioning liabilities			**869**		327
Stock-based compensation			**1,724**		1,935
Unrealized loss on risk management contracts			**8,533**		224
Impairment of property, plant, and equipment			**1,098**		4,023
Exploration expense			**-**		30
Deferred tax recovery			**(699)**		(2,275)
Gain on acquisition	4		**(61)**		-
Gain on sale of securities			**-**		(272)
Other non-cash items			**(19)**		(21)
Funds from operations		**$**	**17,162**	$	20,021
Expenditures on decommissioning liabilities	10	**$**	**(762)**	$	(202)
Changes in non-working capital	15		**2,093**		(34)
Cash provided by operating activities		**$**	**18,493**	$	19,785
Financing activities:					
Increase in bank loan		**$**	**29,650**	$	34,125
Issue of common shares			**62,005**		-
Issue of flow-through shares			**17,000**		-
Exercise of options			**677**		385
Repurchase of common shares			**-**		(750)
Share issuance costs	11(b)		**(2,848)**		(14)
Cash provided by financing activities		**$**	**106,484**	$	33,746
Investing activities:					
Expenditures – property, plant and equipment		**$**	**(112,224)**	$	(58,182)
Expenditures – exploration and evaluation assets			**(6,927)**		(4,430)
Acquisitions	4		**(10,011)**		(23,696)
Sale of securities			**-**		272
Changes in non-cash working capital	15		**1,901**		3,207
Cash used in investing activities		**$**	**(127,261)**	$	(82,829)
(Decrease) in cash and cash equivalents during the year		**$**	**(2,284)**	$	(29,298)
Cash and cash equivalents, beginning of the year			**2,510**		31,808
Cash and cash equivalents, end of the year		**$**	**226**	$	2,510

See accompanying notes to the consolidated financial statements

1. Corporate information

Strategic Oil & Gas Ltd. (“Strategic”) is a company registered and domiciled in Alberta. On April 1, 2012, ZinMac Inc. and Steen River Oil & Gas Ltd., two wholly-owned subsidiaries of Strategic, were amalgamated with Strategic. On February 28, 2013, Strategic acquired all the outstanding common shares of Strategic Transmission Ltd. in conjunction with the acquisition of oil and gas assets in northwest Alberta and the Northwest Territories (see note 4). Strategic Transmission Ltd. has nominal assets and no liabilities.

Strategic is a publicly traded corporation whose shares are listed on the TSX Venture Exchange. Strategic, together with its subsidiaries, (collectively referred to as the “Corporation”) is engaged in the exploration for and development of petroleum and natural gas reserves in Western Canada with insignificant operations in the Western United States. The Corporation is headquartered in Canada at Suite 1100, 645 – 7th Avenue SW, Calgary, Alberta.

2. Basis of presentation

a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) issued and outstanding as of December 31, 2013, and were prepared using accounting policies that are compliant with these standards.

These consolidated financial statements were approved by the Corporation's Board of Directors on March 31, 2014.

b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for cash and cash equivalents, trade and other receivables, bank debt, accounts payable and accrued liabilities, certain share-based payment transactions and derivative financial instruments, which are measured at fair value.

c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, the Corporation’s functional currency.

d) Estimates and judgments

The timely preparation of the consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses for the period. Actual results may differ from these estimates. Information regarding the significant judgments made by management in applying the Corporation's accounting policies and the key sources of estimation uncertainty are outlined below.

The Corporation uses estimates of oil and natural gas reserves in the calculation of depreciation and depletion and also for value in use and fair value less costs to sell (“FVLCS”) calculations of non-financial assets. By their nature, the estimates of reserves, including estimates of price, costs, discount rates and the related future cash flows, are subject to measurement uncertainty.

The recoverability of the carrying value of oil and gas properties is assessed at the cash generating unit ("CGU") level. Determination of the properties and other assets to be included within a particular CGU is based on management's judgment with respect to the integration between assets, shared infrastructure and cash flows. Changes in the assets comprising each CGU impacts recoverable amounts used in impairment assessments and could have a material impact on net income. At December 31, 2012 Strategic had 10 CGUs which were Steen/Marlow, Lessard, Larne, Bistcho, Taber, Conrad, Cheddarville, Maxhamish, Antelope and miscellaneous individual gas wells. Based on a review of the operation, primarily the gathering facilities to take product to market, management has re-evaluated the classification of its assets into CGUs. At December 31, 2013 Strategic conducts its operation through 4 CGUs, namely Steen/Marlow, Bistcho, other Canadian wells and other USA wells.

The transfer of exploration and evaluation assets to property, plant and equipment is based on estimated reserves used in the determination of an asset's technical feasibility and commercial viability.

Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of asset retirement costs, timing of expenditures, risk free interest rates, site remediation and related cash flows.

Derivative financial instruments are measured at fair value which is subject to management uncertainty, due to the use of future oil and natural gas prices and the volatility in these prices.

The determination of fair value of stock-based compensation is based on estimates of future consideration using an option pricing model which requires assumptions such as volatility, risk free interest rate, forfeiture rate, and expected option life.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Corporation operates are subject to change. Income taxes are subject to measurement uncertainty, the timing and likelihood of any recognition of deferred income tax assets, which are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

3. Significant accounting policies

a) Basis of consolidation

Subsidiaries
The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries as follows:

Subsidiary	Jurisdiction	Nature of operations
Strategic Oil & Gas Ltd.	Alberta	Parent company
Strategic Oil & Gas, Inc.	Wyoming, USA	US oil and gas exploration and operations
Jed Oil (USA), Inc.	Wyoming, USA	US holding company
Strategic Transmission Ltd.	Northwest Territories	Holding company

Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Corporation obtains control, and continue to be consolidated until the date that such control ceases. Control exists when the Corporation has the power to govern the relevant activities of an entity so as to obtain benefits from those activities. The consolidated financial statements of the subsidiaries are prepared using consistent accounting policies and for the same reporting period as the parent. All inter-company balances and transactions are eliminated on consolidation.

Jointly operated assets
Interests in jointly operated assets are accounted for using the proportionate consolidated method, so the Corporation has included its proportionate share of revenues, expenses, assets, and liabilities in its accounts.

b) Financial instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or when the Corporation has transferred substantively all the risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount reported in the consolidated balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Subsequent measurement depends upon the classification of the financial instrument as one of:
-Fair value through profit or loss
-Loans and receivables
-Available for sale
-Held to maturity
-Other financial liabilities

Financial assets at fair value through profit or loss
An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments and financial risk management are designated at fair value through profit or loss if the Corporation makes purchase and sale decisions based on their fair value in accordance with the Corporation’s documented risk management strategy. Upon initial recognition, any transaction costs attributable to the financial instruments are recognized through earnings when incurred. Financial instruments at fair value through profit or loss are measured at fair value, and changes therein are recognized in earnings.

Derivative financial instruments
The Corporation has entered into certain financial derivative contracts in order to reduce its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Corporation has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Corporation considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Attributable transaction costs are recognized in earnings when incurred. The estimated fair value of all derivative instruments is based on quoted market prices and/or third party market indications and forecasts.

Financial instruments classified as “loans and receivables”, “held to maturity”, or “financial liabilities measured at amortized cost” are subsequently measured at amortized cost using the effective interest method of amortization.

Financial assets classified as “available for sale” are measured at fair value, with the changes in fair value recognized in other comprehensive income.

The Corporation's financial assets and financial liabilities are classified and measured as follows:

Financial instrument per balance sheet	Classification	Subsequent measurement
Cash and cash equivalents	Fair value through profit or loss	Fair value
Trade and other receivables	Loans and receivables	Amortized cost using effective interest method
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost using effective interest method
Bank indebtedness	Other financial liabilities	Amortized cost using effective interest method
Risk management contracts	Fair value through profit or loss	Fair value

c) Business combinations

The purchase 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 closing. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in the statement of comprehensive loss. Transaction costs that the Corporation incurs in connection with a business combination are expensed as incurred.

d) Exploration and evaluation assets

The Corporation accounts for exploration and evaluation of petroleum and natural gas property ("E&E") costs in accordance with IFRS 6 "Exploration for and Evaluation of Mineral Resources". Costs incurred are classified as E&E costs when they relate to exploring and evaluating a property for which the corporation has the license or right to explore and extract resources.

Pre-license costs are recognized in the statement of comprehensive loss as incurred. E&E costs, including the costs of acquiring undeveloped land, geological and geophysical costs, sampling and appraisals and related drilling costs are initially capitalized until the drilling of the well is complete and the results have been evaluated. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. If proved and/or probable reserves are found, the accumulated costs are tested for impairment and the carrying value net of any impairment is transferred to property, plant and equipment. Undeveloped land costs are amortized over the initial lease term; other E&E costs are not amortized.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

e) Property, plant and equipment

Development and production costs
The Corporation recognized property, plant and equipment ("PPE") assets at cost less accumulated depletion, depreciation and impairment losses.

Items of property, plant and equipment, which include oil and natural gas development and production assets, costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from E&E assets, which generally includes the cost of land and seismic upon determination of technical feasibility and commercial viability; the cost to drill, complete and tie-in the wells; facility costs; the cost of recognizing provisions for future restoration and decommissioning; property acquisitions; and directly attributable overheads. Repairs and maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to profit or loss when incurred.

The costs of planned major overhaul, turnaround activities and equipment replacement that maintain PPE and benefit future years of operations are capitalized. Recurring planned maintenance activities performed on shorter intervals are expensed as operating costs. Replacements outside of a major overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the Corporation and the associated carrying amount of the replaced asset (or part of a replaced asset) is derecognized.

Development and production assets are grouped into Cash Generating Units ("CGUs") for impairment testing and depletion calculations.

When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components). The carrying amount of any replaced or sold component is derecognized.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized in the statement of comprehensive loss.

Depletion and depreciation
The net carrying value of development and production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production and the estimated salvage value of the assets at the end of their useful lives. Natural gas reserves and production are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil, reflecting the approximate energy content. Where significant parts of an item of property, plant, and equipment have different lives than the oil and gas reserves, they are accounted for as separate items (major components) and depreciated over the life of the component.

Proved plus probable reserves are estimated annually by independent qualified reserve evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. The estimated useful lives for certain production assets for the current and comparative years are as follows:

Gas and oil infrastructure	Unit of Production
Development and production assets	Unit of Production
Corporate assets	Straight Line - 5 years
Major components	Straight Line - 20 years
Major overhaul and turnaround activities	Straight Line – 2-3 years, depending on the plant

f) Impairment

Financial assets
A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the statement of loss and comprehensive loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

Non-financial assets
The carrying amounts of the Corporation’s non-financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment at the CGU level. If any such indication exists, then the carrying value of each CGU, including goodwill is compared to its recoverable amount. For goodwill and other intangible assets that have indefinite lives or that are not yet available for use an impairment test is completed each year. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing fair value less costs to sell, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Fair value less cost to sell is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves which are based on forecast prices and costs. Fair value less costs to sell is determined to be the amount for which the asset could be sold in an arm’s length transaction.

E&E assets are allocated to related CGU's when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to producing assets (oil and natural gas interests in property, plant and equipment).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive loss. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

g) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a risk free interest rate. Provisions are not recognized for future operating losses.

Decommissioning liabilities

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or changes in discount rate are capitalized and amortized over the same period as the underlying asset. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent a provision was established.

h) Income tax

Income tax expense comprises current tax and deferred tax. Income tax expense is recognized in comprehensive loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted as of the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

i) Flow-through common shares

Periodically, the Corporation finances a portion of its exploration and development activities through the issuance of flow-through shares. The resource expenditure deductions for income tax purposes related to exploratory development activities are renounced to investors in accordance with tax legislation. Flow-through shares issued are recorded in share capital at the fair value of common shares on the date of issue. The premium received on issuing flow-through shares is initially recorded as a liability. As qualifying expenditures are incurred, the premium is reversed and a deferred income tax liability is recorded. Any difference between the issuance premium and the deferred income tax liability is recognized as deferred income tax expense/recovery.

j) Earnings per share

Basic earnings per share (“EPS”) is calculated by dividing the net loss for the period attributable to equity owners of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, warrants and similar instruments is computed using the treasury stock method. The Corporation’s potentially dilutive common shares comprise stock options and warrants granted to employees and directors.

k) Finance income and expenses

Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning liabilities and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in comprehensive loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Corporation’s outstanding borrowings during the period.

Interest income is recognized as it accrues in comprehensive loss, using the effective interest method.

l) Revenue recognition

Revenue from the sale of oil and natural gas is recognized when the significant risks and rewards of ownership is transferred, which is generally when title passes to the customer in accordance with the terms of the sales contract. Revenue from the production of oil and natural gas form properties in which the Corporation has an interest with other producers is recognized on a net working interest basis.

m) Inventory

Inventory of crude oil, consisting of production for which title has not yet transferred to the buyer, is valued at the lower of cost or net realizable value, based on per barrel weighted average cost of production.

n) New accounting policies

Future Accounting Policy Changes

In May 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which 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 amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by the Corporation on January 1, 2014 and the adoption will only impact the Corporation's disclosures in the notes to the consolidated financial statements in periods when an impairment loss or impairment reversal is recognized.

In May 2013, the IASB issued IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by the Corporation on January 1, 2014 and the adoption does not have an impact on the Corporation's accounting for production and similar taxes, which do not meet the definition of an income tax in IAS 12 "Income Taxes."

The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the consolidated financial statements and provide more opportunities to apply hedge accounting. The Corporation does not employ hedge accounting for its risk management contracts currently in place. In July 2013, the IASB deferred the mandatory effective date of IFRS 9 and has left this date open pending the finalization of the impairment and classification and measurement requirements. IFRS 9 is still available for early adoption. The full impact of the standard on the Corporation's consolidated financial statements will not be known until the project is complete.

Changes in Accounting Policies

As of January 1, 2013, the Corporation 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 Corporation's consolidated financial statements follows below:

IFRS 10 "Consolidated Financial Statements"

This standard supersedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities" and provides a single model to be applied in control analysis for all investees, including special purpose entities. The retrospective adoption of this standard did not have any impact on the Corporation's consolidated financial statements.

IFRS 11 "Joint Arrangements"

This standard divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The retrospective adoption of this standard did not have any impact on the Corporation's consolidated financial statements.

IFRS 12 "Disclosure of Interests in Other Entities"

This standard combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities. The retrospective adoption of the annual disclosure requirements of this standard did not have a material impact on the Corporation's consolidated financial statements.

IFRS 13 "Fair Value Measurement"

This standard defines fair value, establishes a framework for measuring fair value, and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard requires the revaluation of certain derivative financial liabilities on the Corporation's consolidated balance sheets to reflect an appropriate amount of risk of non-performance by the Corporation. The standard also requires additional annual fair value disclosures, as well as additional interim disclosures, as per IAS 34. The prospective adoption of this standard does not have a material impact on the Corporation's consolidated financial statements.

IAS 28 "Investments in Associates and Joint Ventures"

This standard has been amended as a result of changes to IFRS 10 and IFRS 11. The retrospective adoption of these amendments did not have any impact on the Corporation's consolidated financial statements.

IFRS 7 "Financial Instruments: Disclosures" and IAS 32 "Financial Instruments: Presentation"

The amendments to this standard clarify the current requirements for offsetting financial instruments. The amendments to IFRS 7 "Financial Instruments: Disclosures" develop common disclosure requirements for financial assets and financial liabilities that are offset in the consolidated financial statements, or that are subject to enforceable master netting arrangements or similar agreements. The Corporation retrospectively adopted the amendments to both standards on January 1, 2013. The application of these amendments did not have any impact on the Corporation's consolidated financial statements, other than increasing the level of disclosures provided in the notes to the consolidated financial statements.

4. Acquisition

a) On February 28, 2013, the Corporation acquired oil and gas assets in northwest Alberta and the Northwest Territories ("Cameron Hills and Bistcho Assets") for a total cash consideration of $9.7 million.

($000)		December 31, 2013
Property, plant and equipment	$	23,874
Inventory		403
Decommissioning obligations assumed		(14,579)
Gain on acquisition of assets		(61)
Purchase price paid in cash	$	9,637

For the year ended December 31, 2013, the Corporation recorded total revenues of $11.5 million and the net income of $0.60 million in respect of the acquired assets, from the date of acquisition.

b) On January 28, 2013, the Corporation acquired a royalty interest at Steen River for cash consideration of $0.4 million.

c) On December 22, 2012, Strategic acquired oil and gas assets in northwest Alberta ("Steen River Assets") for total cash consideration of $23.7 million. The transaction was accounted for using the acquisition method of accounting for business combinations using management's best estimates of fair values of assets and liabilities acquired as follows:

($000)		December 31, 2012
Property, plant and equipment	$	28,052
Decommissioning obligations assumed		(4,356)
Purchase price paid in cash	$	23,696

The purpose of the acquisition was to complement the Corporation's asset portfolio in Northern Alberta and the Northwest Territories, provide additional opportunities for improved operational efficiencies as well as increase drilling flexibility.

For the year ended December 31, 2012, the Corporation recorded total revenues of $0.1 million and the net income of $0.02 million in respect of the acquired assets, from the date of acquisition.

5. E&E assets

($000)		December 31, 2013		December 31, 2012
Opening balance	$	11,129	$	9,328
E&E expenditures		6,927		4,430
E&E transfer to PPE		(683)		-
E&E expense		-		(30)
Amortization		(2,678)		(2,599)
Closing balance	$	14,695	$	11,129

In 2013 the Corporation expensed $nil (2012 - $0.03 million) related to seismic expenditures on land which is not intended to be further explored in the future.

6. Property, plant, and equipment

($000) Carrying value before accumulated depletion and depreciation	D&P assets	Office	Total
As at December 31, 2012	$ 193,163	$ 858	$ 194,021
Additions	111,976	248	112,224
E&E transfer	683	-	683
Acquisitions	24,249	-	24,249
Change in decommissioning costs	2,209	-	2,209
As at December 31, 2013	**$ 332,280**	**$ 1,106**	**$ 333,386**

($000) Accumulated depreciation and depletion	D&P assets	Office	Total
As at December 31, 2012	$ 56,582	$ 511	$ 57,093
Depreciation and depletion	25,097	257	25,354
Impairment	1,098	-	1,098
As at December 31, 2013	**$ 82,777**	**$ 768**	**$ 83,545**

($000) Net carrying value	D&P assets	Office	Total
As at December 31, 2013	**$ 249,503**	**$ 338**	**$ 249,841**

($000) Carrying value before accumulated depletion and depreciation	D&P assets	Office	Total
As at December 31, 2011	$ 105,145	$ 611	$ 105,756
Additions	57,935	247	58,1822
Acquisition of Steen River assets (note 4)	28,052	-	28,052
Change in decommissioning costs	2,031	-	2,031
As at December 31, 2012	**$ 193,163**	**$ 858**	**$ 194,021**

($000) Accumulated depreciation and depletion	D&P assets	Office	Total
As at December 31, 2011	$ 34,463	$ 369	$ 34,832
Depreciation and depletion	18,096	142	18,238
Impairment	4,023	-	4,023
As at December 30, 2012	**$ 56,582**	**$ 511**	**$ 57,093**

($000) Net carrying value	D&P assets	Office	Total
As at December 31, 2012	$ 136,581	$ 347	$ 136,928

Substantially all of the Corporation's development and production ("D&P") assets are located within Canada. The cost of PPE includes amounts in respect of the provision for decommissioning obligations. For the year ended December 31, 2013, $2.2 million of direct general and administrative expenses were capitalized to PPE ($0.82 million for the year ended December 31, 2012).

Future capital costs of $97.5 million (December 31, 2012 - $49.9 million) have been included in the depletable balance as at December 31, 2013. Depletion has been calculated using proved plus probable reserves. Major components account for $50.4 million (December 31, 2012 - $16.7 million) and are depreciated and tested for impairment separately.

7. Impairment

The Corporation's development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows.

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. These values were based on future cash flows of proved plus probable reserves discounted at a pre-tax rate of 10 percent (2012 – 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 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 15 percent was 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, 2013, the Corporation recognized a PPE impairment of $1.1 million related to the Other Canadian CGU, compared to $4.0 million in 2012 related to the same CGU. Impairment on this CGU arose due to a downward revision of proved and probable reserves at the CGU level.

The impairment test at December 31, 2013 was based the following forward commodity price estimates:

	Natural Gas	**Crude Oil**	
	AECO Gas Price (Cdn$/mmbtu)	Edmonton Par Price (Cdn$/bbl)	West Texas Intermediate (Us$/bbl)
2014	4.00	95.00	95.00
2015	4.25	96.50	95.00
2016	4.55	97.50	95.00
2017	4.75	98.00	95.00
2018	5.00	98.30	95.30
2019	5.25	99.30	96.60
2020	5.35	101.60	98.50
2021	5.45	103.60	100.50
2022	5.55	105.70	102.50
2023	5.65	107.90	104.60
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr

A change in discount rate of 1.0% would have resulted in an additional impairment of $0.005 million for the year ended December 31, 2013 (2012-$0.1 million), while a five percent decrease in the forward commodity price estimate would result in an additional impairment of approximately $0.09 million (2012 - $1.0 million).

8. Deferred price premium on flow-through shares

($000's)		**December 31, 2013**		December 31, 2012
Balance, beginning of the year	**$**	**-**	$	2,275
Additional deferred price premiums on Flow-through shares		**2,318**		-
Flow-through renunciation		**(699)**		(2,275)
Balance, end of the year	**$**	**1,619**	$	-

In 2013, the Corporation issued 15,454,545 common shares on a flow through basis with an estimated aggregate flow through share premium of $2.3 million. In December 2011, the Corporation issued 9,100,000 common shares on a flow through basis with an estimated aggregate flow through premium of $2.3 million. In 2013, a portion of the tax value of the flow through issues was renounced to shareholders and $0.7 million (2012 - $2.3 million) was recognized as a deferred tax recovery in comprehensive loss.

9. Bank loan

The Corporation has a $100 million credit facility (the “Facility”) with a Canadian Chartered bank, comprised of an $80 million revolving operating loan and a $20 million acquisition/development demand loan. 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. The Facility is secured by a general security agreement including a floating charge on all lands. The Facility contains a financial covenant that requires the Corporation 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. In addition to the Facility, the Corporation has $4.1 million letters of credit outstanding with third parties which reduce the amount of funds available under the Facility. The Facility has a renewal date of September 30, 2014.

At December 31, 2013, the Corporation’s adjusted working capital ratio was 0.77, and therefore the financial covenant was not met. Subsequent to year end, the Corporation has received from the lender a waiver of the covenant violation at December 31, 2013.

10. Decommissioning liabilities

Total future decommissioning liabilities are estimated based on the Corporation’s net working interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. These costs are expected to be incurred over a range up to 27 years, depending on the estimated reserve life. The undiscounted amount of the estimated costs at December 31, 2013 were $59.8 million (December 31, 2012 - $25.1 million). The estimated costs have been discounted at a risk free rate from 1.13% to 3.20% (December 31, 2012 – 1.12% to 2.37%) and an inflation rate of 2% (December 31, 2012 – 2%) was applied.

The following table reconciles the changes to the Corporation's decommissioning liabilities:

($000)	December 31, 2013		December 31, 2012	
Balance beginning of the year	$	19,036	$	12,523
Liabilities incurred during the year		875		1,802
Acquisition of liabilities		14,579		4,356
Expenditures on existing liabilities		(762)		(202)
Change in estimated future cash flows		5,263		(113)
Change in discount rate		(3,928)		343
Accretion		869		327
Balance end of the year	$	35,932	$	19,036
Current at December 31, 2013		-		263
Long term at December 31, 2013	$	35,932	$	18,773

11. Share capital

a) Authorized

The Corporation is authorized to issue an unlimited number of common shares without par value.

b) Issued and outstanding

($000)	# of Shares		Amount
Balance as at January 1, 2012	186,562,068	$	122,973
Exercise of warrants and options	812,000	$	672
Shares repurchases	(958,800)		(632)
Share issue costs	-		(14)
Balance as at December 31, 2012	186,415,268	$	122,999
Exercise of options	788,333	$	1,132
Shares issued	73,397,045		76,687
Share issue costs	-		(2,848)
Balance as at December 31, 2013	**260,600,646**	**$**	**197,970**

On March 20, 2013, the Corporation issued 23.2 million common shares via a private placement at a price of $1.25 per common share for gross proceeds of $29.0 million (net proceeds of $28.2 million after transaction costs). Of the $29.0 million gross proceeds, $18.9 million (15.2 million common shares) were acquired by entities that are controlled by a director with the Corporation.

On September 26, 2013, the Corporation issued 20.2 million common shares via a private placement with an entity that shares a common director with the Corporation at a price of $0.95 per common share for gross proceeds of $19.2 million.

On October 7, 2013, the Corporation completed a bought deal financing, resulting in the issuance of 14,547,500 common shares at a price of $0.95 per common shares and 15,454,545 flow-through shares at $1.10 per share for total gross proceeds of $31 million (share issue costs $1.9 million). As at December 31, 2013, the Corporation had spent $5.1 million on qualified exploration and development expenditures to meet the flow through commitment. The remaining committed expenditure is $11.9 million which will be spent in 2014.

On August 16, 2012, the Corporation announced a Notice of Intention to purchase its common shares from time to time in accordance with the normal course issuer bid procedures under Canadian securities laws. Pursuant to the issuer bid, the Corporation may purchase for cancellation up to 9,355,000 of its common shares, representing 5% of the issued and outstanding common shares of the Corporation, during the 12-month period commencing August 20, 2012.

In 2012, the Corporation repurchased and cancelled 958,800 common shares at a weighted average price of $0.78 per common share for a total of $0.75 million, including directly related expenses. Deficit was increased by $0.12 million representing the excess of the purchase price of the common shares over their average carrying value. There were no share repurchases in 2013.

c) Weighted average shares

	December 31, 2013	December 31, 2012
Weighted average shares (basic)	**217,603,874**	186,800,318
Weighted average shares (diluted)	**217,603,874**	186,800,318

12. Stock-based compensation

The Corporation has a stock option plan under which officers, directors, consultants and employees are eligible to receive stock options. The Corporation may reserve for issuance under the plan up to 10% of the issued and outstanding common shares. Options granted under the plan generally have a term of five years and vest at terms to be determined by the directors. Vesting terms have varied from immediate vesting to a three year vesting period. During December 2013, the Corporation issued 1,755,000 common share options of which 1,530,000 will vest over three years and the remaining 225,000 will vest over 5 years. These options expire five years from the date of issue.

The outstanding number and weighted average exercise price of stock options are as follows:

	Number of options	**Weighted average Exercise Price**
Balance - January 1, 2012	**6,780,333**	$ 0.81
Issued	7,385,000	1.06
Exercised	(812,000)	0.47
Expired	(870,000)	1.05
Balance at December 31, 2012	**12,483,333**	$ 0.96
Issued	1,755,000	1.14
Exercised	(788,333)	0.86
Expired	(215,000)	1.27
Balance at December 31, 2013	**13,235,000**	$ 0.98

The following table sets out the outstanding and exercisable options as at December 31, 2013:

Outstanding Options				Exercisable Options	
Number of Options	Weighted Average Exercise Price	Weighted Average Life Years		Number of Options	Weighted Average Exercise Price
1,245,001	$ 0.44	0.52		1,245,001	$ 0.44
1,259,999	0.68	0.99		1,219,999	0.68
755,000	0.84	4.18		425,000	0.84
1,950,000	0.90	3.09		1,950,000	0.90
415,000	0.99	3.96		208,336	0.96
2,145,000	1.10	1.96		2,138,334	1.10
5,070,000	1.16	3.96		3,101,667	1.16
10,000	1.19	4.40		3,334	1.19
85,000	1.24	4.27		28,334	1.24
300,000	1.31	4.06		100,000	1.31
13,235,000	**$ 0.98**	**2.92**		**10,420,005**	**$ 0.94**

The fair value of the options granted was estimated on the date of grant using a Black-Scholes option pricing model with the following weighted average inputs:

	December 31, 2013	December 31, 2012
Assumptions		
Risk free interest rate (%)	**1.66**	1.72
Expected life (years)	**3.79**	3.87
Expected volatility (%)	**81.46**	84.40
Forfeiture rate (%)	**4.24**	7.38
Weighted average fair value of options granted ($)	**0.52**	0.52

The Corporation recorded compensation expense of $1.7 million (2012 – $1.9 million) relating to the stock option plan for the years ended December 31, 2013 and 2012, respectively. Forfeiture rate is calculated based on historical forfeiture data of the Corporation. The weighted average share price at the date of exercise for stock options exercised in 2013 was $1.27 (2012 - $0.93).

13. Finance costs

	Year ended December 31	
($000)	**2013**	2012
Interest expense	**$ 2,595**	$ 103
Foreign exchange gain realized	**(55)**	-
Accretion of decommissioning liabilities	**869**	327
	$ 3,409	$ 430

14. Income Taxes

The following table reconciles the expected income tax expense (recovery) at the Canadian federal and provincial statutory income tax rates to the amounts recognized in the consolidated statements of loss and comprehensive loss for the years ended December 31, 2013 and 2012.

($000)	**2013**	2012
Loss before income taxes	**(23,015)**	(7,063)
Statutory income tax rates	**25.0%**	25.0%
Expected income tax recovery	**(5,754)**	(1,766)
Non-deductible expenses	**6**	14
Non-taxable portion of capital gain on sale of investment	**-**	(34)
Tax effect of flow-through shares	**583**	228
Change in estimates	**170**	1,600
Change in deferred tax benefits realized	**3,864**	(2,797)
Stock-based compensation	**432**	480
Income tax recovery	**(699)**	(2,275)

Details of deferred income tax assets (liabilities) are as follows:

($000)	**December 31, 2013**	December 31, 2012
Deferred income tax assets (liabilities)		
Non-capital loss carry forwards	**44,617**	32,092
Share issuance costs	**963**	758
Oil and gas properties - US	**1,810**	1,810
Oil and gas properties - Canada	**(14,001)**	337
Decommissioning liabilities	**8,985**	4,896
Risk management contract	**2,189**	56
Other	**113**	119
Total gross deferred income tax assets	**44,676**	40,068
Deferred tax benefits not recognized	**(44,676)**	(40,068)
Net deferred tax asset	**-**	-

At this stage of the Corporation's development, it cannot be reasonably estimated at this time that there will be future taxable profits, so no deferred income tax assets were recognized.

As at December 31, 2013, the Corporation has non-capital losses of approximately $178.5 million (2012 - $128.9 million) which may be carried forward to apply against future years' taxable income for Canadian tax purposes, subject to final determination by taxation authorities and expiring as follows:

	($000)
2024	**1,164**
2025	**31,843**
2026	**27,676**
2027	**18,058**
2028	**14,559**
2029	**5,863**
2030	**22,527**
2031	**1,443**
2032	**20,743**
2033	**34,594**
	178,469

15. Supplemental cash flow information

($000)		December 31, 2013		December 31, 2012
Interest paid	**$**	**1,618**	$	103
Taxes paid		**-**		-
Total	**$**	**1,618**	$	103
Changes in non-cash working capital				
Trade and other receivables	**$**	**(107)**	$	(3,337)
Inventory		**(200)**		(179)
Inventory acquired		**403**		-
Accounts payable and accrued liabilities *(1)*		**3,898**		6,689
	$	**3,994**	$	3,173
Operating		**2,093**		(34)
Investing		**1,901**		3,207
	$	**3,994**	$	3,173

(1): Included in the accounts payable and accrued liabilities is $nil (2012 - $19) of non-cash lease inducement.

16. Transactions with related parties

Legal fees in the amount of $0.45 million (2012 - $0.28 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 (2012 - $0.12 million) were incurred to a software firm which is controlled by an officer of the Corporation. Accounts payable and accrued liabilities at 2013 include $0.31 million (2012 - $0.01 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 Corporation and the related parties. Transaction amounts reflect fair values. See note 11 for shares purchased by related party.

Transactions with key management personnel

The Corporation has determined that the key management personnel of the Corporation consists of its officers and directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses, and other benefits. In addition, the Corporation provides share-based compensation to its key management personnel under the long-term incentive plans and the officers participate in the Corporation's share option plan. The compensation included in general and administrative expenses relating to key management personnel for the year is as follows:

($000)	**2013**	2012
Salaries, wages and other short-term benefits	**$ 2,059**	$ 3,321
Stock-based compensation	**860**	1,631
Total compensation	**$ 2,919**	$ 4,952

17. Financial instruments and financial risk management

The Corporation's financial instruments include cash and cash equivalents, trade and other receivables, bank debt, accounts payable and accrued liabilities, certain share-based payment transactions and derivative financial instrument contracts. The carrying values of accounts receivable, accounts payable and accrued liabilities and bank debt approximate their fair values due to their relatively short periods to maturity.

The Corporation is required to classify fair value measurements using a hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy is as follows:

- Level 1 - quoted prices in active markets for identical assets or liabilities;
- Level 2 - inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and
- Level 3 - inputs for the asset or liability that are not based on observable market data.

The fair value of bank debt is measured at level 1. The fair value of risk management contracts is measured at level 2.

The Corporation's risk management policies are established to identify and analyze the risks faced by the Corporation, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Corporation's activities. The Corporation has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. The following presents information about the Corporation's exposure to each of the above risks and the Corporation's objectives, policies and processes for measuring and managing commodity risks. Further quantitative disclosures are included throughout these consolidated financial statements.

a) Market risk

Market risk consists of interest rate risk, currency risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Corporation may use both financial derivatives and physical delivery sales contracts to manage market risks.

Commodity price risk

Commodity price risk is the risk that the fair value of assets or liabilities or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar. The Corporation may, in certain circumstances, enter into forward oil or natural gas sales contracts to mitigate commodity price risk.

At December 31, 2013, the following risk management contracts were outstanding with a mark-to-market liability value of $8.76 million (December 31, 2012 - $0.22 million).

Financial WTI Crude Oil Contracts

Term		Contract Type	Volume (bbl/d)	Fixed Price (CAD$/bbl)	Index
01-Jan-2014	31-Dec-2014	Swap	500	92.00	WTI - NYMEX
01-Jan-2014	31-Dec-2014	Swap	1,000	92.00	WTI – NYMEX
01-Jan-2015	30-Jun-2015	Swap	750	90.15	WTI - NYMEX
01-Jan-2015	31-Dec-2015	Option (1)	600	90.00	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 600 bbl/d option expires on the last business day before the term begins, while the 250 bbl/d option expires monthly during the contract term.

For the year ended December 31, 2013, if oil prices changed by $1.00 per bbl, net income would have changed by $0.7 million.

Financial AECO Gas Contracts

Term		Contract Type	Volume (GJ/d)	Fixed Price (CAD$/GJ)	Index
01-Jan-2014	31-Dec-2014	Swap	1,500	3.50	AECO

Subsequent to December 31, 2013, the Corporation entered into additional financial risk management contracts for 300 GJ/d of gas sales at an AECO price of $3.75/GJ for February to December 2014 and for 500 GJ/d of gas sales at an AECO price of $4.41/GJ for April to October 2014.

For the year ended December 31, 2013, if natural gas prices changed by $0.25 per Mcf, net income would have changed by $0.4 million.

The Corporation does not apply hedge accounting to these risk management contracts and they are recorded as fair value with changes in fair value included in the consolidated statement of loss. For the year ended December 31, 2013, Strategic recorded unrealized losses on risk management contracts of $8.53 million (December 31, 2012 - $0.22 million).

The following table summarizes the fair value as at December 31, 2013 and the change in fair value for the year:

($000)	**December 31, 2013**	December 31, 2012
Net derivative liabilities, beginning of year	**$ (224)**	$ -
Unrealized change in fair value	**(8,533)**	(224)
Net derivative liabilities, end of year	**(8,757)**	(224)
Derivative assets, end of year	**-**	380
Gross derivative liabilities, end of year	**$ (8,757)**	$ (604)

Net realized losses on risk management contracts for the year ended December 31, 2013 was $2.62 million (December 31, 2012 - $nil).

Interest rate risk

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows. The Corporation's primary debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. As at December 31, 2013, if interest rates had increased by 1% with all other variables held constant, net income would have decreased by $1.06 million (2012 – $0.03 million).

Foreign exchange risk

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas and oil prices obtained by the Corporation are influenced by both US and Canadian demand and the corresponding North American supply, and recently, by imports of liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the $CDN as compared to the $US will reduce the prices received by the Corporation for its petroleum and natural gas sales. As at December 31, 2013 and 2012, the Corporation had no contracts in place to mitigate foreign exchange risk.

b) Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Corporation's reputation.

Typically the Corporation ensures that it has sufficient cash on demand to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditure. The Corporation also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Corporation maintains the appropriate reserves based credit facility to provide access capital as needed. It is the Corporation's intent to renew the facility annually (*see note 9*).

c) Credit risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The Corporation's trade and other receivables are with customers and joint venture partners in the oil and gas industry and are subject to normal credit risks. Currently over 93% (2012 – 93%) of the Corporation's oil and natural gas production is being sold through marketing companies and revenues are collected on the 25th day of the month following the month of production. The majority of the remaining accounts receivable are from joint venture partners which are collected between two and four months after the production month. In order to mitigate collection risk, the Corporation assesses the credit worthiness of customers and counter parties by assessing the financial strength of the customers and by routinely monitoring credit risk exposures.

Collection of the remaining balances can be dependent upon industry factors such as commodity prices, risk of unsuccessful drilling and partner disputes. Otherwise, the Corporation does not typically obtain collateral from joint venture partners, and relies upon industry standard legal remedies for collection.

The Corporation's most significant customer, a Canadian oil and natural gas marketer, accounts for 60% of the trade receivables at December 31, 2013 (December 31, 2012: 52%).

The total accounts receivable 90 days past due amounted to $0.68 million at December 31, 2013 (2012 - $1.5 million). The allowance for doubtful accounts at December 31, 2013 was $nil (2012 - $nil).

d) Offsetting financial assets and liabilities

The Corporation's risk management contracts are subject to master agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities simultaneously. The following table summarizes the gross asset and liability positions of the Corporation's risk management contracts that are offset on the balance sheet as at December 31, 2013 and December 31, 2012.

($000)					**December 31, 2013**
	Gross Amount	**Amount Offset**	**Net Amount Prior to Credit Risk Adjustment**	**Credit Risk Adjustment**	**Net Amount**
Current asset	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Long term asset	**-**	**-**	**-**	**-**	**-**
Current liability	**(7,276)**	**-**	**(7,276)**	**-**	**(7,276)**
Long term liability	**(1,481)**	**-**	**(1,481)**	**-**	**(1,481)**
Net position	**$ (8,757)**	**$ -**	**$ (8,757)**	**$ -**	**$ (8,757)**

($000)					December 31, 2012
	Gross Amount	Amount Offset	Net Amount Prior to Credit Risk Adjustment	Credit Risk Adjustment	Net Amount
Current asset	$ 380	$ (380)	$ -	$ -	$ -
Long term asset	-	-	-	-	-
Current liability	(604)	380	(224)	-	(224)
Long term liability	-	-	-	-	-
Net position	$ (224)	$ -	$ (224)	$ -	$ (224)

18. Capital management

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

The Corporation monitors its capital program based on available funds, which is the combination of working capital (excluding deferred price premium on flow-through shares and risk management contracts) and remaining unused line of credit, as calculated below:

($000)		**December 31, 2013**		December 31, 2012
Current assets	**$**	**9,685**	$	11,661
Accounts payable and accrued liabilities, excluding bank loan		**(28,457)**		(25,063)
Net working capital (deficit)	**$**	**(18,772)**	$	(13,402)
Total debt facility *(Note 9)*	**$**	**100,000**	$	48,500
Amount drawn		**(63,775)**		(34,125)
Letters of credit		**(4,139)**		(20)
Unutilized portion of debt facility		**32,086**		14,355
Net available funds	**$**	**13,314**	$	953

The Corporation is currently projecting its 2014 capital program to be approximately $80 million, and expects to fund this program by a combination of cash flow from operations, drawing on the Corporation's credit facility, equity issuances (See Note 21) and other financing sources.

19. Supplemental disclosure

Strategic's consolidated statement of loss and comprehensive loss is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in both operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in the operating and general and administrative expense line items in the consolidated statements of loss and comprehensive loss.

($000)		**2013**		2012
Operating	**$**	**2,802**	$	906
General and administrative		**4,809**		3,702
Total employee compensation costs	**$**	**7,611**	$	4,608

20. Commitments

a) The Corporation has lease agreements for office space and office equipment resulting in the following commitments:

Year ended		**($000's)**
2014	$	338
2015		311
2016		10
	$	659

21. Subsequent events

On March 12, 2014 Strategic entered into an agreement with a syndicate of agents with respect to a private placement of 100,000,000 common shares of the Company at a price of $0.50 per common share, for gross proceeds of $50.0 million. A total of 80,000,000 common shares were purchased by entities controlled by a director of the Corporation. The private placement closed in two tranches on March 24, 2014 and on March 31, 2014. Proceeds were used to reduce bank debt incurred in completing an intensive winter capital program at Steen River.

Strategic OIL & GAS LTD.

Management's Discussion and Analysis

For the three months and year ended December 31, 2013

March 31, 2014

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 year ended December 31, 2013, 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, 2013 and 2012, 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		
	2013	2012	% change	**2013**	2012	% change
Financial ($thousands, except per share amounts)						
Oil and natural gas sales	**15,660**	15,863	(1)	**79,945**	56,512	41
Funds from (used in) operations [1]	**(320)**	3,578	(109)	**17,162**	20,021	(14)
Per share basic & diluted	**(0.00)**	0.02	(100)	**0.08**	0.11	(27)
Cash flow from operating activities	**2,122**	2,724	(22)	**18,493**	19,785	(7)
Per share basic & diluted	**0.01**	0.01	-	**0.08**	0.11	(27)
Net loss	**(9,852)**	(5,917)	67	**(22,316)**	(4,788)	366
Per share basic & diluted	**(0.04)**	(0.03)	25	**(0.10)**	(0.03)	233
Capital expenditures (excluding acquisitions)	**29,484**	15,467	91	**119,151**	62,612	90
Net debt	**82,547**	47,303	75	**82,547**	47,303	75
Operating						
Average daily production						
Oil and NGL (bbl per day)	**1,888**	2,107	(10)	**2,339**	1,871	25
Natural gas (mcf per day)	**5,753**	1,050	448	**5,588**	1,415	295
Barrels of oil equivalent (Boe per day)	**2,847**	2,282	25	**3,270**	2,106	55
Average prices						
Oil & NGL, before risk management ($ per bbl)	**78.87**	80.09	(2)	**85.77**	80.69	6
Oil & NGL, including risk management ($ per bbl)	**76.30**	80.09	(5)	**82.73**	80.69	3
Natural gas ($ per mcf)	**3.71**	3.52	5	**3.30**	2.46	34
Netback ($ per Boe)						
Petroleum and natural gas sales	**59.80**	75.57	(21)	**66.98**	73.30	(9)
Royalties	**11.93**	16.81	(29)	**14.51**	12.55	16
Operating expenses	**34.54**	22.29	55	**24.02**	17.62	36
Transportation expenses	**4.72**	7.38	(36)	**4.57**	7.49	(39)
Operating Netback ($ per Boe) [1]	**8.61**	29.09	(70)	**23.88**	35.64	(33)
Common Shares (thousands)						
Common shares outstanding, end of period	**260,601**	186,415	40	**260,601**	186,415	40
Weighted average common shares (basic)	**258,318**	187,176	38	**217,604**	186,800	16
Weighted average common shares (diluted)	**258,318**	187,176	38	**217,604**	186,800	16

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

FOURTH QUARTER SUMMARY

- Production increased by 565 Boed or 25 percent from 2,282 Boed (92 percent oil) for the three months ended December 31, 2012 to 2,847 Boed (66 percent oil). Production volumes for the current quarter were impacted by 26 days of total downtime at Steen River, related to the 9-17 oil facility expansion and turnaround. The expansion was necessary to increase fluid handling capacity and accommodate future production growth in the Company's core area, as well as increase the efficiency of operations and reduce operating costs.

- Funds from (used in) operations decreased to $(0.3) million for the current three month period from $3.6 million for the comparable quarter in 2012, due to higher operating costs related to the plant turnaround and winter road maintenance charges.

- Three wells were drilled during the quarter, including two Muskeg Stack horizontal wells and the first Keg River horizontal well in the Company's history. All three wells were on production by year-end 2013.

ANNUAL SUMMARY

- Production increased by 55 percent from 2,106 Boed (89 percent oil and NGL) in 2012 to an average of 3,270 Boed (72 percent oil and NGL) in 2013. As a result, oil and gas revenues increased 41 percent to $79.9 million in 2013 from $56.5 million in 2012.

- Funds from operations decreased from $20.0 million in 2012 to $17.2 million in 2013, resulting from higher royalty expense and an increase in operating costs due to a substantial increase in the Company's asset base, partially offset by higher revenues. With the completion of the facility expansion and the Bistcho pipeline operational early in the second quarter of 2014, Strategic anticipates a significant reduction in operating costs, transportation costs and royalty rates as new wells come on stream and production is not hindered by facility downtime.

- Exploration and development expenditures totaled $119.2 million for the twelve months ended December 31, 2013 as compared to $62.6 million for 2012. Approximately 97 percent of exploration and development spending was directed to the Company's light oil asset at Steen River.

- Strategic increased its proved and probable oil and gas reserves by 54 percent compared to the previous year, as determined by the Company's independent reserve evaluators McDaniel and Associates Consultants Ltd. ("McDaniel") at December 31, 2013. The Company added 5.7 MMBoe of proved and probable reserves in 2013, excluding production, for a reserve replacement ratio of 480 percent.

- Strategic closed an acquisition of light oil and natural gas assets at Bistcho in northwest Alberta and Cameron Hills in the Northwest Territories (the "Bistcho/Cameron Hills Assets") on February 28, 2013 for consideration of $9.6 million. This acquisition included operated production of 500 Boed (40% light oil), oil and gas processing facilities and a direct pipeline connection to the Rainbow pipeline in northwest Alberta, which will allow the Company to connect oil production at Steen River to the Rainbow pipeline system. Strategic made immediate operational changes to increase production and reduce operating costs on the acquired properties, and generated operating income of $2.8 million in 2013.

ADVISORIES

Basis of Presentation

This discussion and analysis of Strategic's oil and natural gas production 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 flow generated by operating activities:

	Three months ended December 31		Year ended December 31	
($thousands)	**2013**	2012	**2013**	2012
Cash generated by operating activities	**2,122**	2,724	**18,493**	19,785
Abandonment expenditures	**103**	72	**762**	202
Change in non-cash working capital	**(2,545)**	782	**(2,093)**	34
Funds from operations	**(320)**	3,578	**17,162**	20,021

"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, less royalties, transportation and operating costs.

"Adjusted net working capital" is used to evaluate funds available on the Company's credit facility, and is calculated as current assets less current liabilities, excluding any assets or liabilities related to risk management contracts or the deferred price premium on flow through shares.

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 and opportunity base. Strategic's primary operating area is at Steen River, Alberta.

PERFORMANCE OVERVIEW

In 2013 the Company continued to execute on its corporate strategy to explore and exploit its light oil asset base in northern Alberta, as well as acquiring strategic assets in northern Alberta and the Northwest Territories, including oil and gas production and a 50 km oil pipeline.

Average daily production increased 55 percent from 2,106 Boed in 2012 to 3,270 Boed in 2013, due to a successful drilling program at Steen River and the Bistcho/Cameron Hills acquisition. Strategic was active throughout 2013 at Steen River, drilling a total of twelve (12.0 net) oil wells. The Company drilled six Muskeg Stack horizontal wells, five Keg River vertical wells, and one Keg River horizontal well.

The Company’s operating netbacks were affected by extended production downtime in 2013 as a result of facility constraints, commissioning of new equipment and extremely cold weather in the fourth quarter. Strategic has assembled a concentrated base of land and infrastructure in northern Alberta and operating costs are largely fixed in nature. As new production comes on stream from late 2013 and 2014 drilling and with the processing facilities operating efficiently, the Company anticipates that unit costs and royalty rates will be reduced.

Capital spending in 2013 also included significant facility upgrades and pipeline construction to accommodate production growth and future development at Steen River. The Company now has a total of 8,500 bbl/d of oil processing capacity at its two operated facilities in the area.

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, 2013. Gross reserves included below are Strategic's working interest reserves before royalty burdens.

Strategic’s reserves at December 31, 2013 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	2,991	104	10,118	63	4,845
Proved Non-Producing	112	-	3,360	-	672
Proved Undeveloped	879	-	1,787	-	1,177
Total Proved	**3,982**	**104**	**15,265**	**63**	**6,694**
Total Probable	**3,935**	**39**	**11,979**	**50**	**6,021**
Total Proved and Probable	**7,918**	**143**	**27,244**	**113**	**12,715**

(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.

OUTLOOK

For 2014 Strategic has a capital budget of $80 million that includes drilling Muskeg Stack and Keg River oil wells at Steen River, as well as key infrastructure projects designed to decrease operating and transportation costs in the area.

A significant portion of the first quarter 2014 capital program was directed to the Bistcho pipeline project, initiated to connect crude oil production from the Steen River area to the Rainbow pipeline system. Strategic is also pleased to report its Bistcho oil pipeline project is proceeding on time and on budget. This project is paramount in terms of the Company's strategy to reduce operating and transportation costs by limiting trucking costs and enhancing the profitability of each barrel processed at Marlowe.

The plant turnaround at Bistcho was completed in early March and shut-in production has now been restored. The Bistcho Plant turn around took an extra 10 days to the extreme cold weather. Production volumes averaged approximately 3,100 Boed in January and February and have been steadily increasing as production has been restored at Larne, Bistcho, Cameron Hills and West Marlowe.

Muskeg Stack wells

In the first quarter of 2014 Strategic also drilled three Muskeg Stack wells and completed a fourth well drilled in the fourth quarter of 2013.

Muskeg Stack horizontal well 16-34 was drilled to a lateral length of 1,516 meters and completed with a 14 stage frac. The well averaged 443 BOED (91 percent oil) over the first 11 days of production. This was the first well drilled using completion techniques which have made increased the productivity of the Muskeg Stack horizontal wells. The well is currently producing at a rate of 335 BOED (91% oil) with a liquid level of 25-30 joints to fluid which corresponds to approximately a 30% drawdown.

Muskeg Stack horizontal well 13-24 was drilled to a lateral length of 1,778 meters and completed with a 15 stage frac. The well flowed at a average rate of 310 BOED (85 percent oil) over the first 7 days. The Company has successfully drilled Muskeg Stack horizontal well 10-24, which was the last well drilled during the first quarter drilling program. The well has a lateral length of 1,428 meters and is planned to be completed with a 15 stage frac in early April.

Results for the Muskeg Stack wells are presented in the table below:

Muskeg Hz Well	Lateral Length meters	Frac Stages number	Initial Flow Rate boed (days)	IP30 Boed	Percent Oil %	Current Rate boed	Producing Days days
04-33(4Q13)	1,538	12	654 (IP2)	400	89%	180	132
05-33 (1Q14)	1,506	12	400 (IP4)	260	94%	202	40
16-34 (1Q14)	1,516	14	443 (IP11)	-	91%	335	28
13-24 (1Q14)	1,778	15	310 (IP7)	-	85%	345	8

FOURTH QUARTER RESULTS

Fourth quarter information ($thousands, except where noted)	Three months ended December 31 2013	2012
Average daily production volumes		
Oil & NGL (bbl/d)	**1,888**	2,107
Natural Gas (mcf/d)	**5,753**	1,050
Total (Boed)	**2,847**	2,282
Net loss		
Petroleum and natural gas sales	**15,660**	15,863
Royalties	**(3,126)**	(3,529)
Unrealized loss on risk management contracts	**(1,501)**	(8)
Realized loss on risk management contracts	**(447)**	-
Other income	**-**	278
Revenue, net of royalties	**10,586**	12,604
Operating costs	**9,046**	4,679
Transportation costs	**1,236**	1,550
General and administrative	**1,550**	2,442
Finance costs	**823**	177
Stock-based compensation	**423**	921
Depletion, depreciation and amortization (“DD&A”)	**6,961**	4,729
Impairment of PP&E	**1,098**	4,023
Net loss before taxes	**(10,551)**	(5,917)
Deferred tax recovery	**699**	-
Net loss	**(9,852)**	(5,917)
Net loss per common share	**(0.04)**	(0.03)
Average prices		
West Texas Intermediate (“WTI”) Oil (US$/bbl)	**97.46**	88.18
Oil & NGL price ($/bbl)	**78.87**	80.09
Natural gas price ($/mcf)	**3.71**	3.52
Oil equivalent ($/Boe)	**59.80**	75.57
Funds from operations	**(320)**	3,578
($/common share)	**(0.00)**	0.02
Cash flow provided by operating activities	**2,122**	2,724
($/common share)	**0.01**	0.01
Exploration and development expenditures	**29,484**	15,467
Net acquisitions	**(86)**	23,696

In comparing the fourth quarter of 2013 with the fourth quarter of 2012:

- Oil and NGL production volumes decreased 10 percent as a result of the turnaround and expansion of the 9-17 oil facility at Steen River, as well as extremely cold weather in December, which led to significant downtime in the field.

- Natural gas production volumes increased 448 percent, primarily due to the Bistcho/Cameron Hills assets acquired in March 2013, and associated gas volumes from Muskeg Stack drilling at Steen River

- Oil prices decreased by $1.22/bbl despite an 11 percent increase in WTI prices due to a widening Edmonton light differential in the current period. Natural gas prices increased by $0.19 per Mcf due to an 11 percent rise in AECO daily index prices from period to period.

- Royalty rates decreased from 22.2 percent of revenues in 2012 to 20.0 percent of revenues in 2013, due to a higher percentage of natural gas in the Company's production mix. Natural gas crown royalty rates are lower than rates for oil at current prices.

- Operating costs increased by 93 percent (55 percent on a Boe basis) due to plant turnaround costs at Steen River and a significant increase in the overall scope of Strategic's operations in northwestern Alberta, including the Bistcho/Cameron Hills Assets and oil and gas wells and infrastructure acquired at Steen River in December 2012 ("Other Marlowe"). Current period operating costs included $2.6 million in Bistcho/Cameron Hills and $1.2 million in Other Marlowe. Operating costs are typically highest in the winter months due to road access charges and additional maintenance performed at winter-only access locations. Turnaround costs for the 9-17 facility at Steen River totaled $1.2 million, of which 75 percent was expensed in accordance with the Company's accounting policies. Typically the plant turnaround is done in the third quarter but it was moved to the fourth quarter in 2013 to occur simultaneously with the completion of the facility expansion.

- Transportation costs decreased to $1.2 million ($4.72 per Boe) from $1.6 million ($7.38 per Boe), due to the 10 percent decrease in oil production volumes, partially offset by an increase in natural gas production. The majority of the Company's transportation costs relate to crude oil trucking at Steen River. In 2013 the Company began transporting oil via rail car, which also contributed to the reduction in transportation expense.

- G&A expenses decreased by $0.9 million or 37 percent as compared to the fourth quarter of 2012, primarily due to a decrease in management incentive compensation and higher overhead recoveries resulting from higher capital spending in 2013.

- Finance costs increased by $0.6 million as a result of higher interest costs due to higher debt levels and higher accretion expense related to assets acquired in 2013.

- Stock-based compensation decreased by $0.5 million or 54 percent in 2013, as the Company issued 4.8 million share options in the fourth quarter of 2012 and none in the fourth quarter of 2013.

- Funds from (used in) operations decreased to $(0.3) million or $(0.00) per common share from $3.6 million or $0.02 per share for the fourth quarter of 2012 due primarily to higher operating costs, partially offset by lower G&A expenses.

- DD&A expense increased by 47 percent as production volumes increased 25 percent and the DD&A rate per Boe was 18 percent higher in 2013, as a result of significant facilities expenditures in the second half of 2013.

- Strategic recorded an impairment charge of $1.1 million in the fourth quarter of 2013, related to a non-core property in southern Alberta. Impairment charges totaled $4.0 million for the three months ended December 31, 2012, related to the same property as well as an oil asset in B.C.

- Net loss increased to $9.9 million ($0.04 per basic and diluted common share) from $5.9 million ($0.03 per basic and diluted common share) due primarily to a reduction in funds from operations, higher DD&A expense and an unrealized loss on risk management contracts of $1.5 million, partially offset by lower impairment charges.

- Exploration and development expenditures totalled $29.5 million for the three months ended December 31, 2013 as compared to $15.5 million for the comparable quarter in 2012. Strategic was active in the current quarter, drilling two Muskeg Stack horizontal wells and one horizontal Keg River well. Capital expenditures also included facility expansion costs at 9-17, post drill out operations on four Muskeg Stack wells, well tie-ins and preliminary costs on the Bistcho pipeline project.

RESULTS OF OPERATIONS

Production

	Year ended December 31	
	2013	2012
Oil & NGL – bbl/d	**2,339**	1,871
Natural gas – mcf/d	**5,588**	1,415
Total daily production (Boed)	**3,270**	2,106

Oil & NGL production increased by 468 bbl/d or 25 percent from 2012 due primarily to drilling activities at Steen River and the acquisition of oil production at Cameron Hills. Gas production increased 295 percent due to the Bistcho/Cameron Hills acquisition and associated gas production from Muskeg Stack drilling at Steen River.

The Company's production portfolio in 2013 was weighted 72 percent to oil and NGL and 28 percent to natural gas, a decrease in oil weighting from the 2012 levels of 89 percent to oil and NGL and 11 percent to natural gas.

Revenue

	Year ended December 31	
($thousands, except where noted)	**2013**	2012
Sales		
Oil & NGL	**73,219**	55,241
Natural gas	**6,726**	1,271
	79,945	56,512
Unrealized loss on risk management contracts	**(8,533)**	(224)
Realized loss on risk management contracts	**(2,621)**	-
Other revenue	**94**	370
Total revenue	**68,885**	56,658
Reference prices		
WTI Oil (US$/bbl)	**97.97**	94.21
AECO daily index ($/MMBTU)	**3.16**	2.38
Average prices [1]		
Oil & NGL ($/bbl)	**85.77**	80.69
Oil & NGL, including realized risk management loss ($/bbl)	**82.73**	80.69
Natural gas ($/mcf)	**3.30**	2.46
Oil equivalent ($/Boe)	**66.98**	73.30

[1] Average prices do not include unrealized losses on risk management contracts or other revenue.

The Company's oil and natural gas revenues for the year ending December 31, 2013 increased 41 percent to $79.9 million from $56.5 million in 2012, primarily driven by a 55 percent increase in oil and gas production.

The average price realized for oil and NGL in 2013 increased to $85.77 per bbl from $80.69 per bbl in 2012, due primarily to an increase in WTI oil prices. The Company's average natural gas price increased 34 percent to $3.30 per mcf in 2013 as compared to $2.46 per mcf in 2012 as a result of a 33 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, 2013 is as follows:

Financial WTI Crude Oil Contracts

Term		Contract Type	Volume (bbl/d)	Fixed Price (CAD$/bbl)	Index
01-Jan-2014	31-Dec-2014	Swap	500	92.00	WTI - NYMEX
01-Jan-2014	31-Dec-2014	Swap	1,000	92.00	WTI - NYMEX
01-Jan-2015	30-Jun-2015	Swap	750	90.15	WTI - NYMEX
01-Jan-2015	31-Dec-2015	Option (1)	600	90.00	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 600 bbl/d option expires on the last business day before the term begins, while the 250 bbl/d option expires monthly during the contract term.

Financial AECO Gas Contracts

Term		Contract Type	Volume (GJ/d)	Fixed Price (CAD$/GJ)	Index
01-Jan-2014	31-Dec-2014	Swap	1,500	3.50	AECO

As a result of an increase in the forward price curve for WTI oil, the Company recorded an unrealized loss on risk management contracts of $8.5 million for the year ended December 31, 2013. Unrealized gains and losses on risk management activities do not affect Strategic's funds from operations or cash available for capital spending programs.

Subsequent to the reporting date, Strategic entered into additional fixed-price contracts for February-December 2014 for 300 GJ/d of natural gas sales at $3.75/GJ, and for April-October 2014 for 500 GJ/d of natural gas sales at $4.41/GJ.

Royalties

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 ("GCA"), 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 from which production is derived.

($thousands, except where noted)	Year ended December 31 2013	2012
Crown royalties	**16,536**	8,316
Freehold and overriding royalties	**781**	1,361
Total royalties	**17,317**	9,677
Per Boe	**14.51**	12.55
Percentage of oil & natural gas revenues	**21.7%**	17.1%

In 2011 the provincial government amended its royalty framework to reduce the royalty rate on revenues from newly drilled wells 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. Crown royalties on oil production at Steen River can vary from 10 to 40 percent after the first year of production, depending on well productivity and vintage. On a percentage of revenue and per Boe basis royalties increased in 2013 as a result of Keg River wells drilled in 2012 coming off the first year royalty rate. Royalties increased to $17.3 million for year ended December 31, 2013 from $9.7 million for the period year due to higher revenues, driven primarily by higher oil production.

Operating and Transportation Costs

($thousands, except per Boe amounts)	Year ended December 31 2013	2012
Operating costs	**28,670**	13,581
Transportation costs	**5,449**	5,774
	34,119	19,355
Per Boe		
Operating costs	**24.02**	17.62
Transportation costs	**4.57**	7.49
	28.59	25.11

Operating expenses increased from $13.6 million in 2012 to $28.7 million in 2013 due to a significant increase in the Company's asset base in northern Alberta, as well as additional chemicals and supplies expense related to expanding oil production at Steen River. On a unit basis, operating expenses increased 36 percent to $24.02 per Boe in 2013 compared to $17.62 per Boe for the prior year as a result of higher fixed costs at Steen River and the acquisition of the Bistcho/Cameron Hills assets. Operating costs at Bistcho/Cameron Hills were $7.9 million or $25.60 per Boe for 2013.

Transportation costs decreased by 6 percent or $0.3 million from 2012 levels as Strategic began transporting a portion of its oil production via rail in 2013, which benefits from lower trucking costs. Transportation expenses per Boe declined 39 percent in 2013 due to the rail arrangement and a higher proportion of natural gas in the Company's production mix.

Operating Netbacks

($ per Boe)	Year ended December 31 2013	2012
Revenues	**66.98**	73.30
Royalties	**14.51**	12.55
Operating costs	**24.02**	17.62
Transportation costs	**4.57**	7.49
Netback per Boe	**23.88**	35.64

Strategic's operating netback decreased 33 percent to $23.88 per Boe in 2013 from $35.64 per Boe for 2012 as a result of a lower percentage of oil production in 2013, higher royalty rates and an increase in operating costs due to acquisitions and higher fixed costs at Steen River.

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, 2013, the Company recorded $nil of E&E expense compared to $0.03 million for the same period in the prior year.

General and Administrative Expenses

	Year ended December 31	
($thousands, except per Boe amounts)	**2013**	2012
General and administrative expenses	**6,200**	7,434
Per Boe	**5.19**	9.64

General and administrative expenses ("G&A") decreased to $6.2 million for 2013 from $7.4 million in 2012 as a result of higher overhead recoveries due to increased capital spending and the Company's expanded asset base in the current year, partially offset by higher salaries and information technology costs. G&A per Boe decreased to $5.19 per Boe from $9.64 per Boe in 2012 due to a combination of lower G&A costs and higher production levels.

Finance Expense

	Year ended December 31	
($thousands, except per Boe amount)	**2013**	2012
Interest expense	**2,540**	103
Accretion expense	**869**	327
Total	**3,409**	430
Per Boe	**2.86**	0.56

Finance expense increased to $3.4 million for 2013 from $0.4 million for 2012. Interest expense was considerably higher in 2013 due to an average balance of $56 million on the Company's credit facility during the year, whereas the operating line was not used for much of the previous year. Accretion expense increased by $0.5 million in 2013 due to the increase in Strategic's asset base and resulting decommissioning liabilities.

Going forward the Company intends to use funds from operations to fund capital expenditure programs and acquisitions, as well as drawings on the credit facility and equity or other financings, as deemed appropriate.

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, 2013 the Company recorded $1.7 million in stock based compensation expense as compared to $1.9 million recorded in the previous year. The decrease is primarily due to a lower number of options granted in 2013.

Depletion, depreciation and amortization

	Year ended December 31	
($thousands, except per Boe amounts)	**2013**	2012
Depreciation, depletion, and amortization	**28,033**	20,837
Per Boe	**23.49**	27.03

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, 2013 increased by 34 percent to $28.0 million compared to $20.8 million for 2012, due to 55 percent increase in production levels. On a Boe basis DD&A expense decreased 13 percent to $23.49 per Boe from $27.03 per Boe in 2012, primarily as a result of the low cost per Boe of the Bistcho/Cameron Hills Acquisition.

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.

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. These values were based on future cash flows of proved plus probable reserves discounted at a pre-tax rate of 10 percent (2012 – 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 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 15 percent was 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, 2013, the Company recognized an impairment of $1.1 million related to the Other Canadian CGU, compared to $4.0 million in 2012 related to the same CGU. Impairment on this CGU arose due to a downward revision of proved and probable reserves at the CGU level.

Funds from operations and net loss

($thousands, except per share amounts)	Year ended December 31 2013	2012
Funds from operations	**17,162**	20,021
Per share – basic & diluted	**0.08**	0.11
Cash provided by operating activities	**18,493**	19,785
Per share - basic & diluted	**0.08**	0.11
Net loss	**(22,316)**	(4,788)
Per share – basic & diluted	**(0.10)**	(0.03)

Funds from operations decreased 14 percent to $17.2 million for 2013 from $20.0 million for 2012 as an increase in revenues due to higher production levels was more than offset by higher royalty expense and operating costs.

For the year ended December 31, 2013, the Company recorded a net loss of $22.3 million ($0.10 per basic and diluted common share) compared to a net loss of $4.8 million ($0.03 per basic and diluted common share) in the prior year. The higher net loss in 2013 is a result of higher DD&A charges due to increased production, lower funds from operations and an unrealized loss on risk management contracts of $8.5 million.

Capital Expenditures

($thousands)	Year ended December 31 2013	2012
Drilling and completions	**61,885**	44,115
Equipping and facilities	**50,091**	13,820
Other	**248**	246
	112,224	58,182
Acquisitions	**10,011**	23,696
Total Property, plant and equipment	**122,235**	81,878
Land and seismic	**6,927**	4,430
Total exploration and evaluations	**6,927**	4,430
Total net capital expenditures	**129,162**	86,308

Drilling, completions, equipping and facilities expenditures increased to $112.2 million in 2013 from $58.2 million in 2012. Drilling activities in the current year shifted to focus on horizontal Muskeg Stack oil wells, which are higher cost and typically provide higher production rates than the Keg River wells drilled in 2012. Drilling and completions expenditures for the current year also included an extensive recompletion program at Steen River and Bistcho, confirming oil productivity in multiple zones.

Facility projects in 2013 included a major expansion of the Steen River oil processing facility at 9-17, installation of water disposal facilities, pipeline construction and equipping and tie-in expenditures on wells drilled and recompleted in 2013 and late 2012.

Acquisitions capital spending of $10.0 million in the current year reflects the Bistcho/Cameron Hills Acquisition closed in February 2013. Strategic acquired oil production and significant infrastructure within the Steen River core area for $23.7 million in 2012.

Exploration and evaluation costs are area expenditures where technical feasibility and commercial viability has not yet been determined. Costs incurred prior to lease acquisition are expensed as incurred. Exploration and evaluation costs increased to $6.9 million in 2013 from $4.4 million in 2012 due to 2D and 3D seismic programs conducted at Steen River in the current year.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended ($thousands, except where noted)	Dec 31, 2013	Sept 30, 2013	Jun 30, 2013	Mar 31, 2013
Oil and natural gas sales	**15,660**	22,628	23,770	17,887
Net loss	**(9,852)**	(6,759)	(2,338)	(3,371)
Net loss per share – basic	**(0.04)**	(0.03)	(0.01)	(0.02)
Net loss per share – diluted	**(0.04)**	(0.03)	(0.01)	(0.02)
Average daily production (Boed)	**2,847**	3,510	3,924	2,797
Average realized price ($/Boe)	**59.80**	62.12	67.53	71.05

Quarter ended ($thousands, except where noted)	Dec 31, 2012	Sept 30, 2012	Jun 30, 2012	Mar 31, 2012
Oil and natural gas sales	15,863	12,520	16,924	11,204
Net income (loss)	(5,917)	(718)	1,235	611
Net income (loss) per share – basic	(0.03)	(0.00)	0.01	0.00
Net income (loss) per share – diluted	(0.03)	(0.00)	0.01	0.00
Average daily production (Boed)	2,282	1,930	2,583	1,631
Average realized price ($/Boe)	75.57	70.52	72.00	75.50

Oil and natural gas sales vary with average daily production and realized sales prices, and are higher in 2013 quarters relative to 2012 as a result of increasing production. The fourth quarter of 2013 is an exception as production volumes were impacted by facility downtime and extremely cold weather in December. Net income (loss) will typically fluctuate with production and prices, due to the effect of DD&A expense on earnings. Net loss is higher in 2013 quarters compared to 2012 due to lower realized prices and netbacks, as a result of increasing natural gas production and higher operating costs, partially offset by lower DD&A charges per Boe.

The net loss in the fourth quarter 2012 is largely due to impairment charges recorded of $4.0 million. Net losses in the third and fourth quarters of 2013 were affected by losses on risk management contracts of $5.9 million and $1.9 million, respectively.

LIQUIDITY AND CAPITAL RESOURCES

The Company considers its capital structure to include shareholders' equity, and working capital, including bank debt. 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 program based on available funds, which is the combination of working capital and remaining unused line of credit, as calculated below:

($thousands)	As at December 31 **2013**	 2012
Current assets	**9,685**	11,661
Accounts payable and accrued liabilities	**(28,457)**	(24,839)
Adjusted net working capital surplus (deficit) [1]	**(18,772)**	(13,178)
Total line of credit	**100,000**	48,500
Amount drawn	**(63,775)**	(34,125)
Authorized Letters of Guarantee	**(4,139)**	(20)
Unutilized line of credit	**32,086**	14,355
Net available funds	**13,314**	1,177

[1] This is a non-IFRS measurement. See "Non-IFRS Measurements" in this MD&A.

Credit Facility

The Company has a $100 million credit facility (the “Facility”) with a Canadian chartered bank, comprised of an $80 million revolving operating loan and a $20 million acquisition/development demand loan. Drawdowns on the acquisition/development loan may be made with the approval of the lender for property acquisitions or drilling projects. As of December 31, 2013, Strategic had $63.8 million outstanding under the Facility. Amounts outstanding under the Facility are repayable on demand, and bear interest at a rate of 0.5 percent to 2.5 percent over the bank’s prime lending rate for prime loans, or at bankers’ acceptance rates plus a stamping fee ranging from 1.75 percent to 3.75 percent, depending on Strategic’s debt to cash flow ratio. The Facility is secured by a general security agreement including a floating charge on all lands. Subsequent to the reporting date the Facility was renewed, with the next review date scheduled for September 30, 2014.

The Facility 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 line is included in current assets and, the current portion of bank debt, risk management liabilities and the deferred price premium on flow-through shares are excluded from current liabilities. At December 31, 2013, the Company’s adjusted working capital ratio was 0.77, and therefore the financial covenant was not met. The Company has received from the lender a waiver of the covenant violation at December 31, 2013.

On March 12, 2014 Strategic entered into an agreement with a syndicate of agents with respect to a private placement of 100,000,000 common shares of the Company at a price of $0.50 per common share, for gross proceeds of $50.0 million. A total of 80,000,000 common shares were purchased by entities that share a common director with the Company. The private placement closed in two tranches on March 24, 2014 and on March 31, 2014. Proceeds were used to reduce bank debt incurred in completing an intensive winter capital program at Steen River. Strategic anticipates that with the closing of the private placement, net debt will be approximately $72 million and the Company will be in compliance with its working capital covenant and other Facility covenants.

Going forward the Company intends to use funds from operations and equity financings to fund capital expenditure programs and acquisitions, as well as drawings on the Facility and asset dispositions, as deemed appropriate.

SHARE CAPITAL

	Year ended December 31	
	2013	2012
Outstanding Common shares		
Weighted average Common shares outstanding		
- Basic	**217,603,874**	186,800,318
- Diluted	**217,603,874**	186,800,318

	December 31, 2013	December 31, 2012
Outstanding Securities		
- Common Shares	**260,600,646**	186,415,268
- Common Share Options	**13,235,000**	12,483,333

On March 20, 2013, the Company issued 23.2 million common shares via a private placement at a price of $1.25 per common share for gross proceeds of $29.0 million (net proceeds of $28.2 million after transaction costs). Of the $29.0 million gross proceeds, $18.9 million (15.2 million common shares) were acquired by entities that share a common director with the Company.

On September 26, 2013, the Company issued 20.2 million common shares via a private placement with an entity that shares a common director with the Company at a price of $0.95 per common share for gross proceeds of $19.2 million.

On October 7, 2013, the Company completed a bought deal financing, resulting in the issuance of 14,547,500 common shares at a price of $0.95 per common shares and 15,454,545 flow-through shares at $1.10 per share for total gross proceeds of $31 million (share issue costs $1.9 million). As at December 31, 2013, the Company had spent $5.1 million on qualified exploration and development expenditures to meet the flow through commitment. The remaining committed expenditure is $11.9 million which will be spent in 2014.

During the year 788,333 stock options were exercised for common shares of the Company, for total proceeds of $0.68 million.

SUMMARY OF ANNUAL INFORMATION

	Year ended December 31		
($000, except per share amounts)	**2013**	2012	2011
Total Revenue	**79,945**	56,512	23,853
Net income (loss)	**(22,316)**	(4,788)	(24,646)
Per common share basic)	**(0.10)**	(0.03)	(0.18)
Per common share (diluted)	**(0.10)**	(0.03)	(0.18)
Total Assets	**274,221**	159,718	117,695
Total long-term liabilities	**37,413**	18,773	12,523

Net revenues have increased significantly over the past three years as a result of production additions from successful capital programs, primarily at Steen River, and through acquisitions. Net loss was lowest in 2012 due to higher realized prices and operating netbacks compared to 2011 and 2013, due primarily to a higher proportion of oil in the Company's production mix. Total assets have increased due to capital spending and acquisitions exceeding depletion and depreciation expense over the two-year period. Long-term liabilities consist 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 $0.45 million (2012 - $0.28 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 (2012 - $0.12 million) were incurred to a software firm which is controlled by an officer of the Company. Accounts payable and accrued liabilities at 2013 include $0.31 million (2012 - $0.01 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.

Entities controlled by directors of the Company have also participated in share offerings in 2013 and 2014, as discussed in this MD&A.

COMMITMENTS

The Company has lease agreements for office space resulting in the following commitments:

Year ended	**($000)**
2014	338
2015	311
2016	10
	659

OUTSTANDING SHARE DATA

Common Shares

The Company is authorized to issue an unlimited number of common shares. Including shares issued under the private placements closed in March 2014, the Company had 360,733,978 common shares outstanding and 12,858,335 stock options outstanding under its stock option program as of March 31, 2014.

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)	**2013**	2012
10% increase in oil price	**5,550**	4,527
10% increase in gas price	**683**	131
1% increase in interest rate	**1,052**	(30)

FUTURE ACCOUNTING PRONOUNCEMENTS

In May 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which 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 amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by the Company on January 1, 2014 and the adoption will only impact the Company's disclosures in the notes to the consolidated financial statements in periods when an impairment loss or impairment reversal is recognized.

In May 2013, the IASB issued IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by the Company on January 1, 2014 and the adoption does not have an impact on the Company's accounting for production and similar taxes, which do not meet the definition of an income tax in IAS 12 "Income Taxes."

The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the consolidated financial statements and provide more opportunities to apply hedge accounting. The Company does not employ hedge accounting for its risk management contracts currently in place. In July 2013, the IASB deferred the mandatory effective date of IFRS 9 and has left this date open pending the finalization of the impairment and classification and measurement requirements. IFRS 9 is still available for early adoption. The full impact of the standard on the Company's consolidated financial statements will not be known until the project is complete.

The Company is currently evaluating the impact of adopting all of the newly issued and amended standards.

Changes in Accounting Policies

As of January 1, 2013, 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:

IFRS 10 "Consolidated Financial Statements"
This standard supersedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities" and provides a single model to be applied in control analysis for all investees, including special purpose entities. The retrospective adoption of this standard does not have any impact on the Company's consolidated financial statements.

IFRS 11 "Joint Arrangements"
This standard divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The retrospective adoption of this standard does not have any impact on the Company's consolidated financial statements.

IFRS 12 "Disclosure of Interests in Other Entities"
This standard combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities. The retrospective adoption of the annual disclosure requirements of this standard does not have a material impact on the Company's consolidated financial statements.

IFRS 13 "Fair Value Measurement"
This standard defines fair value, establishes a framework for measuring fair value, and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard requires the revaluation of certain derivative financial liabilities on the Company's consolidated balance sheets to reflect an appropriate amount of risk of non-performance by the Company. The standard also requires additional annual fair value disclosures, as well as additional interim disclosures, as per IAS 34. The prospective adoption of this standard does not have a material impact on the Company's consolidated financial statements.

IAS 28 "Investments in Associates and Joint Ventures"
This standard has been amended as a result of changes to IFRS 10 and IFRS 11. The retrospective adoption of these amendments does not have any impact on the Company's consolidated financial statements.

IFRS 7 "Financial Instruments: Disclosures" and IAS 32 "Financial Instruments: Presentation"
The amendments to this standard clarify the current requirements for offsetting financial instruments. The amendments to IFRS 7 "Financial Instruments: Disclosures" develop common disclosure requirements for financial assets and financial liabilities that are offset in the consolidated financial statements, or that are subject to enforceable master netting arrangements or similar agreements. The Company retrospectively adopted the amendments to both standards on January 1, 2013. The application of these amendments did not have any impact on the Company's consolidated financial statements, other than increasing the level of disclosures provided in the notes to the consolidated 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.

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, lease operating and transportation 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.

Oil and Natural Gas Prices and Marketing

The Company's revenues are dependent upon prevailing prices for oil and natural gas. Oil and natural gas prices can be extremely volatile and are affected by the actions of domestic and international markets, foreign governments, international cartels and the Canadian federal and provincial governments. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation (including tax and royalty regimes) on such production and general economic conditions. All of these factors are beyond the control of the Company. Any decline in oil or natural gas prices could have a material adverse effect on the Company's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves.

The Company may manage the risk associated with changes in commodity prices and foreign exchange rates by, from time to time, entering into crude oil or natural gas price hedges and forward foreign exchange contracts. To the extent that the Company engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to credit risks associated with counterparties with which it contracts.

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. If the Company's future revenues or reserves decline, the Company's ability to expend the capital necessary to undertake or complete future drilling programs may be limited. There can be no assurance that debt or equity financing or cash generated by operations 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, future activities may require Strategic to alter its capitalization significantly, and potentially increase the Company's debt levels above industry standards. 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 dridrilling 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 royalty rates; (vi) anticipated operating and service costs; (vii) incremental development opportunities; (viii) total shareholder return; (ix) anticipated compliance with credit facility covenants; (xii) asset disposition plans; (xiii) 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, 2013 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.