Management's Discussion and Analysis

Three months ended March 31, 2011

June 2, 2011

Strategic Oil & Gas Ltd. ("Strategic" or the "Corporation) was incorporated under the laws of the Province of British Columbia on December 30, 1987 and continued as an Alberta corporation on September 9, 2010. On March 29, 2006, Strategic incorporated a United States of America (USA) subsidiary, Strategic Oil & Gas, Inc. ("US Subsidiary") through which all oil and gas activities in the USA are conducted. ZinMac Inc. ("ZinMac"), a private oil and gas consulting company was acquired on March 10, 2009, and Steen River Oil & Gas Ltd. ("Steen River"), a private oil and gas exploration and production company, was acquired on December 22, 2010 by Strategic. The three month period ended March 31, 2011 is the first interim period for which the Corporation has prepared its financial statements under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

Financial and Operations Overview

For the three months ended March 31, 2011 and 2010

(thousands of dollars except per share amounts and shares outstanding)

	2011	2010
	$	$
Funds from operations *	**(1,295)**	38
Per share – basic	**(0.01)**	0.00
Net Income (loss)	**(4,891)**	(1,226)
Per share – basic	**(0.04)**	(0.02)
Average production (boe/d)	**790 boe/d**	315 boe/d
Capital expenditures		
Land and seismic	**3,444**	425
Drill and complete	**6,047**	1,556
Property acquisitions	**---**	---
Equipment, facilities and other	**2,431**	242
	11,922	2,223
Common shares o/s at period-end (000's)	**138,555**	68,693

** before changes in non-cash capital*

HIGHLIGHTS

- A net loss of $4,891,000 was recorded in the period.

- Spent $11.9 million on the capital expenditure program in the first quarter, primarily at Steen River and Maxhamish.

- Steen River winter program was successfully implemented and included:

    - Repair of the crude oil pipeline at Steen River (Marlowe North) by late January, 2011
    - Completion of a $3.2 million 3-D and 2-D seismic program at Marlowe North
    - Completion of a 6 well workover and optimization program at Marlowe North and Marlowe West
    - Drilled, completed and tied in two successful Keg River oil wells at Marlowe North (8-22 and 10-22)
    - Completed an all year access road to core areas of Marlowe North

- Committed to a drilling rig from Akita Drilling Ltd. from August, 2011 to April, 2012 for use primarily at the Steen River area.

- Acquired an additional 38 sections (24.320 acres) of 100% working interest land in the North and West Marlowe areas of Steen River. These lands were acquired for an average of $250 per hectare and are contiguous to Strategic's current Steen River landholding.

- Completed an all season road and well pads with its partner at Maxhamish. The all season infrastructure will facilitate drilling, completion and production operations through most of the year.

- March exit production was 1,150 boe/d as a result of the successful workover program in the Steen River area.

- Line of credit was recently increased from $5.0 million to $21.0 million, reflecting the increased reserve base from the Steen River acquisition and the subsequent workover and drilling program.

ADVISORIES

The following Management Discussion and Analysis ("MD&A") of financial results is dated June 2, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the period ended March 31, 2011 and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010. The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting Standards" ("IFRS"). Previously the Corporation prepared its interim and annual consolidated financial statement in accordance with Canadian generally accepted accounting principles ("previous GAAP").

The calculation of barrels ("bbl') of oil equivalent ("boe") is based on a relative energy content conversion of six thousand cubic feet ("mcf") of natural gas to one equivalent barrel of oil (6 mcf=1bbl) when measured at burner tip and does not represent a value equivalency at the wellhead. Production volumes reported are the Corporation's interest before royalties, unless otherwise stated, and all amounts are expressed in Canadian dollars, unless otherwise stated.

Certain financial measures referred to in this discussion, such as funds from operations are not prescribed by IFRS or the previous Canadian GAAP in Canada, so are considered non-GAAP measures. Funds from operations represents cash generated from operating activities before changes in non-cash working capital and asset retirement expenditures. The Corporation considers funds from operations a key measure that demonstrates the ability to generate cash to fund expenditures.

Management believes that in addition to net earnings, funds from operations is a useful supplemental measure to assess the financial performance and the ability of Strategic to finance future growth through capital investment. In addition, management uses netback to analyze operating performance and leverage. Netback equals total revenue less royalties, operating costs and transportation costs calculated on a per boe basis.

The adoption of IFRS has not had a material impact on the corporation's operations, strategic decisions and cash flow. Further information on the IFRS impacts is provided in the International Financial Reporting Standards Section of the MD&A including reconciliations between previous GAAP and IFRS net loss and other financial metrics.

Forward-looking information
Certain information set forth in this document, including management's assessment of future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, many of which are beyond management's control. Those risks include, without limitation, the effect of general economic conditions, risks associated with oil and gas exploration, development, production, marketing and transportation, loss of markets, the fact that Strategic does not operate all of its properties, industry conditions and competition, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the ability to access qualified personnel and oilfield services, decisions by regulators and the ability to access sufficient capital from internal and external sources. Readers are cautioned not to place undue reliance on the forward-looking statements as the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and actual results, performance or achievements could materially differ from those expressed or implied in such forward-looking statements and accordingly, no assurance can be given that any of the events anticipated by forward looking statements will transpire or occur, or if any of them do so, what benefit Strategic will derive therefrom.

Specific forward-looking statements include the following:

***Maxhamish program*.** Specific risks include the geologic and operational risks associated with any well. In addition, the area is currently subject to winter access only and there are facilities required to handle significant production. In addition, as the Corporation is not the operator, it is bound by the decisions of the operator in respect to future development programs, the timing of the same and the requirement of having to raise capital in order to participate. The Corporation also faces the risk of not being able to raise sufficient capital in the future in a timely manner due to the status of the capital markets at such time.

Steen River program. Specific risks include the allocation of capital to the drilling program and successful results. In addition, much of the area is currently subject to winter access only. Although the Corporation currently has available funds for these wells, there is no assurance that competing projects may require a re-allocation of funds. The success of these wells and achievement of the projected production is subject to the geologic and operational risks associated with any well.

OVERVIEW OF PERFORMANCE AND DISCUSSION OF OUTLOOK

The three months ended March 31, 2011 showed an increase in volumes over the comparable period of 2010. Average daily sales volumes increased by 151% to 790 boe/d in 2011 versus 315 boe/d in 2010. Revenues also increased by 186% to $4,613,896 for 2011 versus $1,689,641 in 2010. The increase was the result of the 150% increase in production and 9% increase in product prices realized in the first quarter of 2011 over same period in 2010. The Corporation received an average price of $64.85 per boe versus $59.44 in 2010 which is an increase of 9%.

For the three months ended March 31, 2011 average daily production was 790 boe/d versus 317 boe/d for the fourth quarter of 2010. Revenues for the first quarter of 2011 were $4,613,896 versus $1,639,920 in the fourth quarter of 2010. The increase in production and revenues is the result of a full two months of production included from the Steen River acquisition following resumption of pipeline access in the current quarter and oil prices improving over the quarter. The Corporation received an average price of $64.85 per boe in the first quarter of 2011 versus $56.21 per boe in the fourth quarter of 2010, a 15% increase.

For the three months ended March 31, 2011, the Corporation had a net loss of $4,891,099 or $0.04 per share basic and diluted as compared to a net loss of $1,225,601 of $0.02 per share for the three months ended

March 31, 2010. The loss in 2011 arises from the stock-based compensation expense of $2,657,400 as a result of the issuance of stock options in the quarter and increased operating expenses. Negative funds from operations for the three months ended March 31, 2011 was $1,294,800 as compared to a funds from operations of $37,861 for the three months ended March 31, 2010.

As previously disclosed, on December 22, 2010, Strategic closed an arms-length acquisition of all of the issued and outstanding shares of Steen River Oil & Gas Ltd. ("Steen River"), a private oil and gas exploration and production company.

At the time of acquisition, production was approximately 250 boe/d with additional production shut-in as a result of a pipeline break. In late January, 2011 the pipeline was repaired and an additional 400 boe/d of production was brought back on-stream. Total production from this field at that time was approximately 650 boe/d, of which greater than 2/3 is light oil.

In the first quarter of 2011, Strategic completed two Keg River wells, a 3D seismic program and an all weather road into the North Marlow area of Steen River. Based on the preliminary results from the workover program, Strategic exited March with production of approximately 1,150 boe/d. Results of the two Keg River drills are currently being assessed.

At Maxhamish, the 2011 development program is proceeding. The all weather road and well pad is nearing completion. The all season infrastructure will facilitate drilling, completion and production operations through most of the year. Drilling operations are expected to commence in the near future with completion of up to 4 multi-frac horizontal wells by the fourth quarter.

OUTLOOK FOR 2011

Maxhamish

At Maxhamish, the 2011 development program is proceeding.

This includes:

- i) building a year-round access road to be completed by early June to improve access to the area;
- ii) licensing and construction of drilling pads that can accommodate up to 8 wells per pad;
- iii) drilling up to 4 wells by the fourth quarter of 2011, with completions to follow;
- iv) building infrastructure where necessary, including battery, pipelines; and
- v) assessment of future drilling program.

Steen River, northwest Alberta

At Steen River, where the Corporation has a 100% working interest and operates the field, Strategic has moved forward aggressively to develop the property. This included shooting a $3.2 million 3-D and 2-D seismic program, workovers on 6 wells, building a year round road into certain core areas of the property and drilling two Keg River oil wells. The seismic program is currently being interpreted, and combined with the regional geological study currently being performed will help determine future drilling locations for late summer or early fall drilling. A pipeline leak in late April, 2011 shutdown the Rainbow pipeline, which transports the Corporation's Steen River crude oil to market. Strategic is still moving approximately 50% of its crude oil and natural gas to market through alternate routes. The start-up date is not known, but this will impact the Corporation's sales volumes in the second quarter.

Strategic has signed an agreement with Akita Drilling Ltd. to secure a drilling rig from August 2011 to April 2012. Over the next 12 months Strategic plans to drill up to 10 wells in Steen River.

Production has increased steadily from December 31, 2010 with March production of approximately 1,150 boe/d due to the repair of the pipeline, workovers and optimization at Steen River. An additional production increase is anticipated in the second quarter from the drilling of two successful Keg River wells at Steen River.

Summary

Strategic is in a unique position for a junior/emerging oil and gas company:

i) it is financed with a working capital balance of $10 million at the end of the first quarter and a recently signed $21 million line of credit;
ii) ongoing development at Maxhamish, with over 100 sections of land;
iii) 140 sections of undeveloped land at Steen River, an area with proven light oil potential; and
iv) politically and fiscally stable environment.

IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY

Crude oil prices have increased through the early months of 2011, and the Corporation was able to raise over $46,000,000 equity in the previous year. The Corporation is therefore in a strong position to undertake its planned capital expenditures program. In addition, the Corporation has recently announced an increase in its line of credit with a Canadian financial institution from $5.0 million to $21.0 million. The Corporation will continue to monitor its funds from operations, cash position and available credit facilities to ensure its ability to meet its planned capital program for 2011.

RISK FACTORS

Additional risk factors may be found on page 12 of this Management Discussion and Analysis under "Financial Instruments".

RESULTS OF OPERATIONS

Production

Three months ended March 31	**2011**	2010
Oil, condensate, & ngls – bbls/d	**564**	226
Natural gas – mcf/d	**1,358**	535
Boe/d	**790**	315

Production for 2011 for the three months ended March 31, 2011 averaged 790 boe per day consisting of 1,358 mcf per day of natural gas, 564 bbls per day of crude oil and ngl's. Production during the quarter was 151% higher than the same period in 2010 of 315 boe per day. The increase can be attributed towards the acquisition of Steen River assets on December 22, 2010, restoration of a pipeline break and recompletion operations in the Steen River area. The normal operations from the pipeline were resumed January 24, 2011. The production continued to increase in the second quarter and was 1500 boe per day after the production from the two new Keg River oil wells commencing in mid April 2011.

The Corporation's production portfolio for the quarter was weighted 29% to natural gas and 71% to crude oil and natural gas liquids.

Revenue

Three months ended March 31	**2011** **$**	2010 $
Sales		
Oil, condensate, and ngls	**4,132,748**	1,440,029
Natural gas	**481,149**	246,578
Total sales	**4,613,897**	1,686,607
Average prices		
Oil and ngls ($/bbl)	**81.39**	70.75
Natural gas ($/mcf)	**3.94**	5.12
Oil equivalent ($/boe)	**64.85**	59.44

The average price received for oil, condensate and ngls was $81.39 per bbl as compared to $70.75 per bbl reflecting a 15% price increase. The first quarter of 2011 natural gas price was $3.94 per mcf as compared to $5.12 per mcf in the first quarter of 2010.

Crude oil and natural gas revenue increased by 186% from the first quarter of 2011 to the same period of 2010. Overall, the combined price in the first quarter of 2011 of $64.85 per boe is 9% higher than the combined price of $59.44 per boe in the first quarter of 2010. The increase in revenues is the result of a 150% increase in production and 9% increase in product prices realized in the first quarter of 2011.

Royalties

Three months ended March 31	**2011** **$**	2010 $
Crown royalties	**1,151,348**	162,465
Freehold royalties	**19,981**	20,462
Overriding royalties	**105,225**	29,144
Net royalties	**1,276,554**	212,071
Per boe	**17.94**	7.47
Percentage of revenues	**27.7%**	12.6%

For the quarter, royalties increased fivefold to $1,276,554 from $212,071 for the same period in 2010. On a boe basis, the average royalty increased by 140% from $7.47 to $17.94. The increase is mainly due to an increase in production and increase in prices. The average percentage of revenue increased from 12.6% to 27.7% as the Steen River crude oil production attracts an average royalty rate of nearly 40% as it reaches the maximum rate under the new Alberta royalty framework.

On March 3, 2009 the Alberta government announced incentives for the energy sector in response to the global economic slowdown. The incentives include a drilling royalty credit for new conventional oil and natural gas wells of up to $200 per meter drilled for wells spud on or after April 1, 2009 to March 31, 2011, and a maximum five percent royalty rate for the first year of production from new oil or gas wells brought on production after April 1, 1009, up to a maximum of 500,000 mcf of natural gas or 50,000 bbls of crude oil production.

- On March 11, 2010, the Alberta government announced further changes to its royalty regime as a result of its “Competitiveness Review” which will take effect beginning January 1, 2011. The key changes are:

- the current incentive program of five percent for the first year of production on new natural gas and conventional oil wells will become permanent with the time and volume limits as currently stated;

- the maximum royalty rate for conventional oil will be reduced at higher price levels from 50 percent to 40 percent;

- the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50 percent to 36 percent; and

- the transitional royalty framework will continue until its original announced expiration on December 31, 2013. However, effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates.

Operating and transportation costs

Three months ended March 31	**2011** **$**	2010 $
Operating costs	**3,305,131**	648,706
Transportation costs	**146,369**	59,763
	3,451,500	708,469
Per boe		

Operating costs	**46.46**	22.86
Transportation costs	**2.06**	2.11
	48.52	24.97

The net operating costs increased to $3,451,500 in the first quarter 2011 from $708,469 for the equivalent period in 2010 due to the increase associated with the acquisition of Steen River assets as well as work over costs on oil and natural gas wells.

Operating costs on a boe basis averaged $48.52 per boe for the first three months of 2011 compared to $24.97 for the corresponding period in 2010. Strategic had anticipated these higher operating costs in the first quarter of 2011 arising from the integration of the Steen River assets. Costs were higher for several reasons:

i) reduced volumes of Steen River from the pipeline break and related high fixed cost components of the facility.
ii) winter operations inherently have higher costs due to annual maintenance and repair programs.
iii) a workover and optimization program was initiated much of which is non-recurring operating expense.

The Corporation has budgeted operating costs of less than $25.00 per boe for the remainder of 2011.

Exploration and Evaluation Expense

Three months ended March 31	**2011 $**	2010 $
Exploration and Evaluation *(1)*	**181,395**	0
Per boe	**2.55**	0

Note (1): Exploration and Evaluation for the three months ended March 31, 2011 has been presented as a result of adopting IFRS with a transition date of January 01, 2010.

All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas are capitalized as exploration and evaluation assets pending determination of technical feasibility and commercial liability. The costs included in exploration and evaluation expense generally include pre-license costs, undeveloped land and geophysical and geological costs. If the assets are subsequently determined to be technically feasible and commercially viable, the exploration costs are tested for impairment and then reclassified from exploration and evaluation assets to development and production assets. If exploratory costs are determined not to be technically feasible and commercial viable, the costs are expensed as exploration and evaluation expense.

For the three months ended March 31, 2011, the Corporation expensed exploration and evaluation costs of $181,395 related to unsuccessful projects.

Operating netbacks

Three months ended March 31	**2011 $**	2010 $
Per boe		
Revenues	**64.85**	59.44
Royalties	**(17.94)**	(7.47)
Operating costs	**(46.46)**	(22.86)
Transportation costs	**(2.06)**	(2.11)
Netback per boe	**(1.61)**	27.00

The decrease in operating netback for the quarter ending March 31, 2011 is mainly due to increase in operating costs and royalties primarily related to the Steen River properties in comparison to the same period ended 2010. Significant components of the operating costs in the first quarter are non-recurring. The higher revenue from the light crude oil will allow for significantly improved netbacks as the production increases at Steen River.

General and administrative expenses

Three months ended March 31	**2011** **$**	2010 $
Wages and employee benefits	**546,254**	314,722
Professional fees	**63,814**	9,231
Consulting fees	**231,711**	132,564
Public reporting	**98,922**	35,576
Occupancy costs	**113,340**	85,622
Travel	**54,874**	28,724
Miscellaneous general and administrative	**64,411**	84,167
Total	**1,173,326**	690,606
Per boe	**16.49**	25.30

General and administrative expenses per boe net of overhead recoveries decreased by 35% to $16.49 per boe basis for the first quarter of 2011 compared to $25.30 for the same period in 2010. Total general and administrative costs increased to $1,173,326 for the first three months of 2011 from $690,606 for the same time period in 2010. The overall costs increased due to staffing increases and consulting costs associated with higher activity levels arising from the Steen River acquisition. The cost per boe is anticipated to drop in the remainder of 2011, reflecting higher production volumes.

Finance Expense

Three months ended March 31	**2011** **$**	2010 $
Interest expense – bank loan	**13,408**	39,468
Interest expense – debenture	**42,287**	-
Accretion expense *(1)*	**51,317**	33,048
Total	**107,012**	72,516
Per boe	**1.50**	2.55

Note (1): Accretion for the three months ended March 31, 2010 was restated and reclassified for the effect of adopting IFRS.

Finance expenses during the quarter increased by 48% to $107,012 compared to $72,516 for the same period in 2010. Interest incurred is a result of bank borrowing. Interest expense decreased in the first quarter of 2011 compared to the same period in 2010 due to lower debt levels. Interest on the debenture was due to the assumption of debt as part of the acquisition of Steen River.

Accretion represents the change in time value of the decommissioning liability. Accretion expense increased for the three months ended March 31, 2011 compared to the same period of 2010 due to new obligations from wells drilled, and the acquisition of crude oil and natural gas assets. The underlying liability may increase over a period based on new obligations incurred from drilling wells, constructing facilities, acquiring operations or adjusting future estimates of timing or amounts. Similarly this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations.

Stock based compensation

Stock based payments are non-cash charges which reflect the estimated value of stock options issued to directors and employees of Strategic. The value of the award is recognized as an expense over the period from the grant date to the date of vesting of the award.

For the period ended March 31, 2011, the Corporation recorded $2,657,400 of expense from the issuance of 3,125,000 common share options which were issued in January, 2011 and vested immediately.

Depletion, depreciation and accretion

Three months ended March 31	**2011** **$**	2010 $
Depreciation, depletion, and amortization *(1)*	**1,758,578**	504,754

Per boe	**24.72**	17.79

Note (1): Depletion and depreciation for the three months ended March 31, 2010 was restated for the effect of adopting IFRS.

Depletion and depreciation is computed on a unit of production basis. Such expense, on a boe basis, fluctuates period to period primarily as a result of changes in the underlying proved and probable reserve base and in the amount of costs subject to depletion and depreciation. Such costs are segregated and depleted on an area by area basis relative to the respective underlying proved and probable reserves base. The depletion and depreciation expense for the three months ended March 31, 2011 increased by 248% to $1,758,578 compared to the same period in 2010 at $504,754. On a boe basis, the costs increased by 39% to $24.72 compared to $17.79 for quarter ending March 31, 2010. The increase is the result of higher capital and future development costs subject to depletion, offset by the higher additions to the proved and probable reserves base.

Funds from operations and net income (loss)

Three months ended March 31	**2011 $**	2010 $
Funds (used in) from operations*(1)*	**(1,294,800)**	37,861
Per share		
basic	**(0.01)**	0.00
diluted	**(0.01)**	0.00
Net income (loss)*(1)*	**(4,891,099)**	(1,225,601)
Per share		
basic	**(0.04)**	(0.02)
diluted	**(0.04)**	(0.02)

Note (1): Funds from operations and net income for the three months ended March 31, 2010 were stated and reclassified for the effect of adopting IFRS.

The decrease in funds from operations for the first quarter of 2011 is attributable to the higher revenues offset by higher operating and general and administrative expenses. The Corporation generated a net loss for the first quarter of 2011 of $4,891,099 compared to $1,225,601 during the three months ended March 31, 2010. The increase in net loss is the result of increase in operating expenses, general and administrative costs and stock base compensation in 2011.

Capital Expenditures

Three months ended March 31	**2011 $**	2010 $
Drilling and completions	**6,162,336**	631,203
Facilities	**2,419,193**	1,869
Other	**12,571**	2,831
	8,594,100	635,903
Drilling incentive credits	**(116,314)**	-
Total Property, plant and equipment	**8,477,786**	635,903
Land and seismic	**3,444,008**	1,556,365
Total exploration and evaluations	**3,444,008**	1,556,365
Total net capital expenditures	**11,921,794**	2,192,268

The Board of Directors of the Corporation has approved a 2011 capital budget of $25 million, prior to consideration of any acquisitions.

Capital spending in the first quarter of 2011 was significantly higher than the first quarter of 2010 due to the following activities:

- Participation in two new wells (2.0 net) at Steen River

- Four recompletions/workovers at Steen River
- Construction of an all weather access road to the 10-22 pad at Steen River
- Equip and tie-in of 2 gas wells with artificial lift to handle increased liquids at Steen River
- Completion of a $3.2 million 3-D and 2-D seismic program at Steen River
- Construction of an all year access road and drilling pads at Maxhamish

Exploration and evaluation costs are area expenditures where technical feasibility and commercial viability has not yet been determined. Costs incurred prior to acquisition are expensed as incurred. Exploration and evaluation costs increased due to shooting and processing of seismic in order to evaluate potential drilling locations.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended	Mar-11 $	Dec-10 $	Sep-10 $	Jun-10 $	Mar-10 $
Petroleum and natural gas sales	4,891,099	1,639,921	1,504,357	1,293,250	1,686,606
Income (loss)	(4,684,099)	3,091,917	(1,219,336)	(985,892)	(682,392)
Income (loss) per share Basic Diluted	 (0.04) (0.04)	 .03 .03	 (0.02) (0.02)	 (0.02) (0.02)	 (0.01) (0.01)
Production boe/d	790	317	314	266	315
Average price/boe	64.85	56.21	52.08	53.38	59.44

LIQUIDITY AND CAPITAL RESERVES

The Corporation started 2011 with working capital of $25,286,239 including the debentures. During the first quarter of 2011, negative funds of $1,294,800 were generated from operations and $11,921,794 was expended on capital projects. The Corporation has a working capital surplus of $9,905,238 at March 31, 2011, which includes $19,470,145 of cash in the bank.

The Corporation monitors its capital program based on available funds, which is the combination of working capital and remaining unused line of credit, as calculated below:

	March 31, 2011 **$**
Current assets	**24,281,176**
Accounts payable and accrued liabilities	**(10,950,713)**
Debentures	**(3,425,225)**
Net working capital surplus	**9,905,238**
Total line of credit	**21,000,000**
Year end loan balance	**0**
Unutilized line of credit	**21,000,000**
Net available funds	**30,905,238**

The Corporation is currently projecting its remaining 2011 capital program to be in the range of $13 million, and expects the current available funds plus cash flow will be able to fund it.

The valuation of the credit facility is based on petroleum and natural gas reserves with certain financial covenants. The credit facility also contains a financial covenant that requires the Corporation to maintain a working capital ratio of not less than 1:1, but for the purposes of the ratio calculation the unused portion of the facility is included in current assets, and the current portion of the debt is excluded from current liabilities. As at March 31, 2011, this ratio was 2.7:1. Subsequent to the quarter end, the Corporation signed an indicative term sheet to increase its line of credit with its financial institution to $21 million under the same terms and conditions as the current loan.

SHARE DATA

At June 2, 2011 Strategic had 139,001,661 common shares, and 6,888,335 stock options with a weighted average exercise price of $0.82 per share outstanding. In addition, all warrants were exercised subsequent to the quarter end.

Common Shares
Authorized:

Unlimited number of common shares without par value

Issued:	Number of shares	$
Balance, December 31, 2010	**138,555,366**	**82,427,513**
Share issue costs		(5,404)
Balance, March 31, 2011	**138,555,366**	**82,422,109**

Subsequent to the quarter end, approximately 370,370 shares were issued upon the exercise of warrants for proceeds of $100,000.

Stock options
The following table reconciles the changes to the Corporation's stock options for the three months ended March 31, 2011:

	Number of options	Exercise Price $
Balance – December 31, 2010	**3,846,667**	**0.59**
Issued	3,125,000	1.10
Balance – March 31, 2011	**6,971,667**	**0.82**

In January, 2011, 3,125,000 common share options were issued with an exercise price of $1.10 per share expiring in five years from date of issue, and vest immediately. The fair value of the options were calculated using the Black-Scholes model using an expected volatility of 102.4%, interest rate of 2.6%, estimated forfeiture rate of 8.2%, expected life of 5 years and no expected dividends resulting in $2,657,400 of stock-based compensation.

The following table sets out the outstanding options as at March 31, 2011:

All stock options, issued and exercisable		
Number of Options	**Exercise price**	**Weighted Average Life (yrs)**
701,667	$0.25	2.95
1,235,000	$0.50	3.36
1,275,000	$0.65	3.79
435,000	$0.75	2.95
3,125,000	$1.10	4.77
200,000	$1.60	1.09
6,971,667	**$0.82**	**3.91**

Warrants
The following table reconciles the changes to the Corporation's warrants for the quarter ended March 31, 2011:

Number

	of warrants	Exercise price
Opening balance – December 31, 2010	**370,370**	**$0.27**
Closing balance – March 31, 2011	**370,370**	**$0.27**

All warrants vested immediately. Subsequent to the quarter end, all of these warrants were exercised for proceeds of $100,000.

TRANSACTIONS WITH RELATED PARTIES

Legal fees and expenses in the amount of $45,327 ($20,583 – March 31, 2010) were incurred to a legal firm of which a director is a partner, and included as general and administrative expenses or share issue costs. Consulting fees in the amount of $5,566 ($11,769 – March 31, 2010) were incurred to a director for geophysical consulting services. Software charges of $30,000 (nil – March 31, 2010) were charged to a company controlled by an officer. Accounts payable and accrued liabilities at March 31, 2011 include $62,065 ($24,338 – March 31, 2010) 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.

COMMITMENTS

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

Year ended	$
2011	234,447
2012	292,596
2013	263,213
	790,256

b) Pursuant to the issues of flow through shares on October and December 2010, the Corporation is committed to incur prior to December 31, 2011, a total of $11,448,250 on qualifying expenditures. As at March 31, 2011, $6,401,767 has been incurred toward this commitment.

FINANCIAL INSTRUMENTS

The Corporation's financial instruments consist of cash and cash equivalents, short term investments, trade and other receivables, accounts payable and accrued liabilities, bank loan, and debentures. The carrying value approximates fair value due to the immediate or short term maturity of these instruments.

The Corporation is exposed to a number of different financial risks from normal course business exposures, as well as the Corporation's use of financial instruments. These risk factors include market risk, liquidity risk, and credit risk.

a) **Market Risk**
Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the Corporation's financial assets, liabilities and expected future cash flows include commodity price risk, interest rate risk and foreign exchange risk.

i) Commodity Price Risk
The Corporation's financial performance is closely linked to natural gas and crude oil prices. While the Corporation may employ the use of various financial instruments in the future to manage these price exposures, the Corporation is not currently using any such instruments. The Corporation may, in certain circumstances, enter into oil or natural gas hedging contracts to provide stability of future cash flows by fixing the price of future deliveries of saleable product. As at March 31, 2011, the Corporation had no hedging contracts.

	March 31, 2011	March 31, 2010
	$	$

10% change in oil price	**287,564**	127,056
10% change in gas price	**46,170**	20,398

ii) 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 March 31, 2011, if interest rates had increased by 1% with all other variables held constant, net income would have decreased by $50,061 (2009 – decrease $4,882). The change in net income for an interest rate that is 1% lower would also increase by $3,636 (2009 – increase $12,140).

iii) Foreign exchange risk

Although the Corporation's product revenues are denominated in Canadian dollars, the underlying market prices are affected by the exchange rate between the Canadian and United States dollar. As at March 31, 2011, the Corporation had no contracts in place to reduce the 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 believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and undrawn committed borrowing facilities to meet current spending forecasts. All of the corporation's liabilities mature in 2011 as the Corporation's accounts payable are due in demand. There was no loan balance at March 31, 2011, so minimal additional liquidity risk.

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 accounts receivable are with customers and joint venture partners in the oil and gas industry and the Government of Canada for GST refunds, and are subject to normal credit risks. The Corporation's production is predominately sold by taking its product in kind and revenues are collected on the 25th day of the month following the month of production. The majority of the remaining balances of account receivable are from joint venture partners which are collected between two and four months after the production month. As at March 31, 2011, the Corporation's receivables were as follows:

	March 31, 2011 **$**
Joint venture partners	145,170
Petroleum and natural gas marketers	1,313,916
Other	2,210,448
Prepaid expenses	1,141,497
Total accounts receivable	**4,811,031**

As at March 31, 2011, the aging analysis of trade receivables, excluding prepaid expenses, is as follows:

	March 31, 2011 **$**
Current	1,850,675
30 – 60 days	163,188
60 – 90 days	613,478
Greater than 90 days	1,042,193
Total	**3,669,534**

At March 31, 2011, the amount receivable for Alberta Crown Royalties was $967,459 and steps are being taken to recover this balance.

CRITICAL ACCOUNTING ESTIMATES

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

Crude oil and natural gas assets – reserves estimates
The Corporation retained GLJ to evaluate its crude oil and natural gas reserves, prepare an evaluation report, and report to the Corporation. 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 Corporation's depletion calculations and impairment tests. Property, plant and equipment within each area are depleted using the unit-of-production method based on proved 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.

Under the IFRS, the carrying amount of property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the estimated recoverable amount is calculated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset of a CGU is the greater of its value in use and its fair value less costs to sell. Fair value less costs to sell represent the value for which an asset could be sold in an arms length transaction, and is presented as a function of the future cash flows of the proved and probable reserves. In assessing value in use, 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. Value in use 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. E&E assets are allocated to the related CGU's to assess 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 in income if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the impairment test. Revisions of these estimates could result in a write-down of the carrying amount of crude oil and natural gas properties.

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 the future periods. These costs are expected to be incurred over a range up to 22 years, depending on the estimated reserve life. The undiscounted amount of the estimated costs at March 31, 2011 were $15,979,935 (December 31, 2010 - $15,459,560). The estimated costs have been discounted at a risk free rate of 3.66% (December 31, 2010 – 3.51%) and an inflation rate of 2% at March 31, 2011 (December 31, 2010 – 2%).

Stock based compensation
The Corporation has a stock option plan under which officers, directors 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 between a three year vesting period and all options vesting immediately.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Corporation's IFRS accounting policies are approved in *Note 3* to the condensed interim consolidated financial statements. In addition, *Note 18* to the interim consolidated financial statements present reconciliations between the Corporation's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial positions as at January 1, 2010, March 31, 2010 and December 31, 2010 and consolidated statements of earnings and comprehensive income and cash flows for the three months ended March 31, 2010 and year ended December 31, 2010. The following discussion explains the significant difference between IFRS and the Previous GAAP followed by the Corporation.

a) Property, plant and equipment

Under Previous GAAP, the Corporation, like many Canadian oil and Gas reporting issuers, applied the "full cost" concept in accounting for its oil and gas assets. Under full cost accounting, capital expenditures were maintained in a single cost centre and the cost centre was subject to a single depletion and depreciation calculation and impairment test. Under IFRS, the Corporation makes a much more detailed assessment of its oil and gas assets that impact depreciation and impairment calculations. Included in this assessment is an ongoing appraisal of exploration and evaluation expenditures ("E&E"). Under Canadian GAAP, it was only necessary to track costs associated with unproved properties that would be excluded from depletion and depreciation calculations. Under IFRS, a company may choose to account for E&E under its previous GAAP and capitalize such costs without recording depreciation expense until the expenditures are determined to represent technically feasible and commercially viable projects at which time the costs are moved to development properties or expenses accordingly. The Corporation capitalizes E&E costs except for costs incurred before the acquisition of rights to explore, and to begin depreciating when technically feasible and commercially viable. As at transition on January 1, 2010, $NIL was reclassified from property, plant and equipment to exploration and evaluation assets.

As well, under Previous GAAP the Corporation did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more while IFRS requires such recognition. This results in an increase to the carrying value and a gain on sale of property, plant equipment.

b) Exploration and Evaluation

Costs associated with acquiring an exploration license, including costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees are capitalized as exploration and evaluation assets. Geological and geophysical costs (including seismic) associated with assessing exploration licenses are also capitalized to E&E. Land acquisition costs and expenditures directly associated with exploratory wells are capitalized and remain capitalized until the Corporation has chosen to discontinue all exploration activities in the associated area. Costs directly associated with an exploration well are capitalized as exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated.

Land acquisition costs, related seismic and costs directly associated with exploratory wells with proved reserves are tested for impairment and reclassification to PP&E. If no reserves are found, the capitalized exploration costs are charged to expense as exploration expense, including dry hole costs.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved reserves are determined to exist. A review of each exploration area is carried out, at least annually, to ascertain whether proved reserves have been discovered. Upon determination of proved reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to property, plant, and equipment.

E&E assets are assessed for impairment if (i) sufficient data exists to determine the lack of technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation asset are allocated to cash-generating units.

As at December 31, 2010, the Corporation transferred $5,724,148 from PP&E to E&E as the commercial viability was established.

c) **Depreciation**

For Previous Canadian GAAP purposes, the full cost method of accounting for oil and gas properties requires a single calculation of depletion and depreciation of the carrying value of PP&E based on proved reserves. However, IFRS requires an allocation of the amount recognized as PP&E to each significant identified component and each component depreciated separately, utilizing an appropriate method of depreciation. This component depreciation of PP&E results in an increased number of calculations of depreciation expense and impacts the amount of depreciation calculation. The Corporation has utilized proved and probable reserves to calculate depreciation expense as the Corporation believes it represents a better approximation of useful life and depletion of reserves.

d) **Impairment of Assets**

Under previous Canadian GAAP, impairment calculations are prepared according to a two-step test generally conducted at a country level. Step one involves a comparison of the PP&E carrying value to the undiscounted net cash flows of proved reserves. If a company should fail step one, step two is completed to measure the amount of impairment whereby the PP&E carrying value is compared to a calculated fair value with any excess carrying value above the fair value recognized as an impairment loss. Impairment losses recognized under Canadian GAAP are not subsequently reversed. Under IFRS, impairment testing is completed at an individual asset group or "Cash Generating Unit" level ("CGU") when indicators suggest there may be impairment. A CGU is defined as the smallest measuring asset that produces independent cash flows. Impairment of assets at a CGU level use a one-step approach for testing and measuring asset impairment, with asset carrying values compared to the higher of "Value in Use" and "Fair Value less Costs to Sell". The IFRS methodology may result in the possibility of more frequent impairments in the carrying value of PP&E. However, under IFRS previous impairment losses must be reversed where circumstances change such that the previously recognized impairment has been reduced.

e) **Decommissioning Liabilities**

Both previous Canadian GAAP and IFRS require a company to provide for a liability related to decommissioning PP&E. Both methodologies are similar and the Corporation has determined there to be no significant difference for the Corporation, other than a difference related to discount rates. Canadian GAAP previously required that the decommissioning liability be discounted at a credit-adjusted risk-free rate while IFRS requires that the decommissioning liability be discounted at an appropriate rate with either the cash flows or rate adjusted for risks. The Corporation has selected to use the risk–free rate for discounting purposes and at transition date the decommission liability was increased by $1,084,844 and charged to deficit.

f) **Deferred Income Taxes**

Deferred income tax calculated according to IFRS is substantially similar to Previous GAAP and arises from differences between the accounting and tax bases of our assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax liability has been impacted. Additionally, under Previous GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

On transition of IFRS on January 1, 2010, the Corporation used certain exemptions allowed under IFRS 1 First Time Adoption of International Reporting Standards. These exemptions used were as follows:

i) **Shared-Based Compensation** – IFRS I allows an entity an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vest before the Corporation's transition date to IFRS.

Future Accounting Pronouncement

Standards issued but not yet effective up to the date of issuance of the Corporation's financial statements are listed below. This listing is of standards and interpretations issued which the Corporation reasonably expects to be applicable at a future date. The Corporation intends to adopt those standards when they become effective.

i) **IFRS 9 Financial Instruments: Classification and Measurement**
IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring assets and liabilities, which may affect the Corporation's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 9.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation is recorded, processed, summarized and reported within the time periods specified under the Canadian securities law. The Corporation's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, that the disclosure controls and procedures as of the end of March 31, 2011, are effective and provide reasonable assurance that material information related to the Corporation is made known to them by others within the Corporation.

The Corporation's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal controls over financial reporting ("ICFR"). They have, as at the quarter ended March 31, 2011, designed ICFR or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposed in accordance with IFRS. The control framework of the Corporation's officers used to design the ICFR is the Internal Control – Integrate Framework issued by the Committee of Sponsoring Organizations.

The Corporation's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting that occurred during our most recent interim period that has materially affected, or is reasonably likely to affect, the Corporation's internal controls over financial reporting. No material changes in the internal controls were identified during the period ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Further information with respect to the Corporation can be found on its website at www.sogoil.com and on the SEDAR website: www.sedar.com.