Strategic Oil & Gas Ltd.

Statement of Reserves Data and Other Oil and Gas Information

For the Period Ended December 31, 2011
Dated April 18, 2012

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Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. The information in this document is stated as at December 31, 2011, unless otherwise indicated. For an explanation of the capitalized terms and expressions and certain defined terms, please refer to the section of this document titled "*Notes and Definitions*".

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Bcf	billion cubic feet
GJ	gigajoule
MMBTU	million British Thermal Units
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
McfGE	1,000 cubic feet of gas equivalent on the basis of 6 McfGEs to 1 bbl of crude oil. McfGEs may be misleading, particularly if used in isolation. A McfGE conversion ratio of 6 McfGEs to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
McfGE/d	1,000 cubic feet equivalent per day
MMcfGE	1,000 McfGE
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000s	thousands of dollars

Conversion

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

All forward-looking statements in this document and in certain documents incorporated by reference herein, are based on assumptions and the Corporation's (as defined below) view of future events which reflect information available at the time the assumption was made. Certain statements contained in this document constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Management of the Corporation believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included herein should not be unduly relied upon. These statements speak only as of the date hereof or at the date specified in the documents incorporated by reference into this Annual Information Form.

In particular, this document contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and continually add to reserves through exploration, development and acquisitions; and
- treatment under governmental regulatory regimes including taxation.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this document:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;

- competition for, inter alia, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- failure to realize the anticipated benefits of acquisitions.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this document or otherwise, and while the Corporation may choose to do so, it accepts no obligation other than as required by law, to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise.

THE CORPORATION

Strategic Oil & Gas Ltd. ("**Strategic**" or the "**Corporation**") was incorporated under the laws of B.C. and continued as an Alberta corporation on September 9, 2010. The registered office of the Corporation is located at 3700, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2 and its head office is located at 1800, 510 – 5th Street SW Calgary, Alberta T2P 3S2

NOTES AND DEFINITIONS IN RESPECT TO RESERVE REPORT

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

The following terms, used in the preparation of the GLJ Report (as defined herein) and this document, have the following meanings:

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“**Discovered Petroleum Initially In Place (DPIIP)**” is equivalent to discovered resources and is defined in the Canadian Oil and Gas Evaluation Handbook (“COGEH”) as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. “Contingent Resources” are defined in COGEH as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be economically recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The Contingent Resources estimates and the DPIIP estimates are estimates only and the actual results may be greater or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources except to the extent identified as proved or probable reserves. “Best estimate” is defined in COGEH with respect to entity-level estimates, as the value derived by an evaluator using deterministic methods that best represent the expected outcome with no optimism or conservatism. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"**future prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"**gross**" means:

(a) in relation to the Corporation's interest in production or reserves, its "corporation gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**net**" means:

(a) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the well site.

OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, GLJ Petroleum Consultants ("GLJ") prepared a report (the "GLJ Report") dated March 21, 2012. The GLJ Report evaluated, as at December 31, 2011, Strategic's crude oil, NGL and natural gas reserves in Canada and the United States. The GLJ January 1, 2012 future price forecast was used to determine all estimates of future net revenue. The tables below are a summary of Strategic's crude oil, NGL and natural gas reserves and the net present value of future net revenue attributed to such reserves as evaluated in the GLJ Report based on future price and cost assumptions. The tables summarize the data contained in the GLJ Report and due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs, general and administrative costs and income taxes, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by GLJ represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of Strategic's crude oil, NGL, and natural gas reserves provided herein are estimated only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimated provided herein.

The GLJ Report is based on certain factual data supplied by the Corporation and GLJ's opinion of reasonable practice in the industry, including requirements under National Instrument 51-101. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

RESERVES SUMMARY

	Light and Medium Oil		**Heavy Oil**		**Natural Gas**		**Natural Gas Liquids**		**Total Oil Equivalent**	
Reserves Category	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl	Company Gross MMcf	Company Net MMcf	Company Gross Mbbl	Company Net Mbbl	Company Gross Mbbl	Company Net Mbbl
PROVED										
Producing	1,509	1,115	152	147	2,437	2,138	62	46	2,129	1,664
Developed Non-Producing	39	27	0	0	575	513	0	0	135	112
Undeveloped	913	659	0	0	240	207	(1)	(1)	952	693
TOTAL PROVED	**2,461**	**1,801**	**152**	**147**	**3,252**	**2,858**	**61**	**45**	**3,215**	**2,469**
TOTAL PROBABLE	**1,486**	**1,082**	**73**	**70**	**2,666**	**2,326**	**51**	**40**	**2,055**	**1,579**
TOTAL PROVED PLUS PROBABLE	**3,947**	**2,883**	**226**	**217**	**5,919**	**5,184**	**112**	**84**	**5,271**	**4,048**

NET PRESENT VALUE SUMMARY

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0%	**5%**	**10%**	**15%**	**20%**		
Reserves Category	M$	M$	M$	M$	M$	$/boe	$/Mcfe
PROVED							
Producing	65,669	54,638	47,033	41,495	37,287	28.27	4.71
Developed Non-Producing	2,635	2,078	1,669	1,360	1,123	14.88	2.48
Undeveloped	31,145	23,940	19,457	16,450	14,305	28.08	4.68
TOTAL PROVED	**99,449**	**80,656**	**68,159**	**59,305**	**52,714**	**27.60**	**4.60**
TOTAL PROBABLE	**61,390**	**39,781**	**28,171**	**21,194**	**16,628**	**17.84**	**2.97**
TOTAL PROVED PLUS PROBABLE	**160,839**	**120,437**	**96,330**	**80,500**	**69,342**	**23.80**	**3.79**

	Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	M$	M$	M$	M$	M$
PROVED					
Producing	65,669	54,638	47,033	41,495	37,287
Developed Non-Producing	2,635	2,078	1,669	1,360	1,123
Undeveloped	31,145	23,940	19,457	16,450	14,305
TOTAL PROVED	**99,449**	**80,656**	**68,159**	**59,305**	**52,714**
TOTAL PROBABLE	**61,390**	**39,781**	**28,171**	**21,194**	**16,628**
TOTAL PROVED PLUS PROBABLE	**160,839**	**120,437**	**96,330**	**80,500**	**69,342**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Proved Producing	169,640	39,337	58,901	3,525	2,207	65,669	0	65,669
Proved Developed Nonproducing	6,903	1,405	2,014	611	237	2,635	0	2,635
Proved Undeveloped	89,410	24,371	23,632	9,894	368	31,145	0	31,145
Total Proved	**265,952**	**65,113**	**84,547**	**14,030**	**2,813**	**99,449**	**0**	**99,449**
Total Probable	**176,843**	**43,234**	**57,169**	**14,222**	**828**	**61,390**	**0**	**61,390**
Total Proved plus Probable	**442,795**	**108,347**	**141,715**	**28,252**	**3,641**	**160,839**	**0**	**160,839**

Notes and Definitions

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this annual information form, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic estimation methods is required to properly use and apply reserves definitions.

Pricing Assumptions – Forecast Prices and Costs

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of January 1, 2012 in estimating the Corporation's reserves data using forecast prices and costs.

	Natural Gas			Crude Oil	Natural Gas Liquids			
Year	Midwest Price @ Chicago ($US/MMBTU)	AECO-NIT Spot (C$/MMBTU)	WTI @ Cushing ($US/BBL)	EDM Ref Price ($/BBL)	Ethane ($/BBL)	Propane ($/BBL)	Butane ($/BBL)	CDN/US Exchange Rate
2012 Q1	3.60	3.21	97.00	97.96	10.50	58.78	76.41	0.980
2012 Q2	3.75	3.35	97.00	97.96	10.98	58.78	76.41	0.980
2012 Q3	3.95	3.54	97.00	97.96	11.61	58.78	76.41	0.980
2012 Q4	4.30	3.86	97.00	97.96	12.72	58.78	76.41	0.980
2012 Full year	3.90	3.49	97.00	97.96	11.46	58.78	76.41	0.980
2013	4.60	4.13	98.04	101.02	13.67	60.61	78.80	0.980
2014	5.10	4.59	96.12	101.02	15.26	60.61	78.80	0.980
2015	5.60	5.05	94.23	101.02	16.85	60.61	78.80	0.980
2016	6.10	5.51	92.38	101.02	18.43	60.61	78.80	0.980
2017	6.60	5.97	90.57	101.02	20.02	60.61	78.80	0.980
2018	6.86	6.21	90.00	102.40	20.84	61.44	79.87	0.980
2019	6.99	6.33	90.00	104.47	21.25	62.68	81.49	0.980
2020	7.13	6.46	90.00	106.58	21.70	63.95	83.13	0.980
2021	7.27	6.58	90.00	108.73	22.14	65.24	84.81	0.980
2022+	+2.0%/yr	+2.0%	90.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.980

All prices escalate at 2% per year after 2021

The weighted average sales prices realized by Strategic for the year ended December 31, 2011 were $3.83/mcf for natural gas, and $88.92 Cdn/bbl for crude oil and natural gas liquids.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

The following table sets forth a reconciliation of Strategic's gross company interest reserves comprising total proved, total probable and total proved plus probable reserves as at December 31, 2011 against such reserves as at December 31, 2010 based on forecast price and cost assumptions.

RECONCILIATION OF COMPANY GROSS RESERVES
TOTAL CANADA & USA
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2010	1,628	1,323	2,951	1,474	1,252	2,726	154	71	225	88	75	163
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	119	40	159	119	40	159	0	0	0	0	0	1
Infill Drilling*	215	1,051	1,266	215	1,051	1,266	0	0	0	0	0	0
Improved Recovery*	6	1	7	6	1	7	0	0	0	4	1	5
Technical Revisions	871	(824)	47	848	(828)	20	23	4	27	(17)	(25)	(42)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	7	(31)	(24)	6	(29)	(23)	1	(2)	(1)	(3)	0	(3)
Production	(233)	0	(233)	(207)	0	(207)	(26)	0	(26)	(12)	0	(12)
December 31, 2011	2,613	1,560	4,173	2,461	1,487	3,947	152	73	226	61	51	112

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2010	5,369	4,321	9,690	5,369	4,321	9,690	0	0	0	2,611	2,118	4,729
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	35	16	51	35	16	51	0	0	0	125	43	168
Infill Drilling*	457	406	862	457	406	862	0	0	0	291	1,119	1,410
Improved Recovery*	4	(1)	3	4	(1)	3	0	0	0	11	1	12
Technical Revisions	(1,338)	(2,061)	(3,399)	(1,338)	(2,061)	(3,399)	0	0	0	630	(1,192)	(562)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	(251)	(15)	(266)	(251)	(15)	(266)	0	0	0	(38)	(33)	(71)
Production	(1,023)	0	(1,023)	(1,023)	0	(1,023)	0	0	0	(415)	0	(415)
December 31, 2011	3,252	2,666	5,919	3,252	2,666	5,919	0	0	0	3,215	2,056	5,271

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

RECONCILIATION OF COMPANY GROSS RESERVES
CANADA - EVALUATED PROPERTIES
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2010	1,628	1,324	2,951	1,474	1,253	2,727	154	71	225	87	75	162
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	119	40	159	119	40	159	0	0	0	0	0	1
Infill Drilling*	215	1,051	1,266	215	1,051	1,266	0	0	0	0	0	0
Improved Recovery*	6	1	7	6	1	7	0	0	0	4	1	5
Technical Revisions	875	(840)	35	851	(843)	8	24	4	27	(19)	(26)	(44)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	4	(16)	(12)	3	(15)	(12)	1	(1)	(1)	(2)	0	(2)
Production	(233)	0	(233)	(207)	0	(207)	(26)	0	(26)	(12)	0	(12)
December 31, 2011	2,613	1,560	4,173	2,461	1,487	3,947	152	73	226	60	51	110

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2010	5,292	4,296	9,588	5,292	4,296	9,588	0	0	0	2,596	2,115	4,711
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	35	16	51	35	16	51	0	0	0	125	43	168
Infill Drilling*	457	406	862	457	406	862	0	0	0	291	1,119	1,410
Improved Recovery*	4	(1)	3	4	(1)	3	0	0	0	11	1	12
Technical Revisions	(1,477)	(2,066)	(3,543)	(1,477)	(2,066)	(3,543)	0	0	0	610	(1,210)	(600)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	(125)	(8)	(133)	(125)	(8)	(133)	0	0	0	(19)	(17)	(36)
Production	(1,007)	0	(1,007)	(1,007)	0	(1,007)	0	0	0	(412)	0	(412)
December 31, 2011	3,179	2,643	5,821	3,179	2,643	5,821	0	0	0	3,202	2,051	5,253

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

RECONCILIATION OF COMPANY GROSS RESERVES
USA - EVALUATED PROPERTIES
BY PRINCIPAL PRODUCT TYPE

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2010	o	0	0	0	0	0	0	0	0	1	0	1
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	6	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	(0)	0	(0)
December 31, 2011	0	0	0	0	0	0	0	0	0	1	0	1

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2010	78	25	102	78	25	102	0	0	0	14	4	18
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	00	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	12	(1)	11	12	(1)	11	0	0	0	2	1	3
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	(16)	0	(16)	(16)	0	(16)	0	0	0	(3)	0	(3)
December 31, 2011	74	24	97	74	24	97	0	0	0	13	5	18

** The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions may be combined and reported as "Extensions and Improved Recovery".*

Undeveloped Reserves

The following discussion generally describes the basis on which the Corporation attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the year or wells further away from the Corporation's gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

L&M Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Conventional Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**		**BOE (Mbbl)**	
Attributed 2011[1]	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
666	913	0	0	(984)	240	(20)	(1)	482	952

Note: Attributed refers to the incremental reserves booked in the current year.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and land contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

L&M Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Conventional Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**		**BOE (Mbbl)**	
Attributed 2011[1]	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
149	931	-1	24	-36	615	-23	30	-196	1,088

Note: Attributed refers to the incremental reserves booked in the current year.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by GLJ.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment will affect these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves, using forecast prices and costs.

Company Annual Capital Expenditures ($M)			
	Proved Producing	Total Proved	Total Proved +Probable
2012	3,525	11,323	22,387
2013	-	2,382	4,810
2014	-	-	-
2015	-	27	451
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	-	-	-
2020	-	-	-
2021	-	299	299
2022	-	-	305
2023	-	-	-
Total	3,525	14,030	28,252

The Corporation estimates that its internally generated cash flow and cash on hand will be sufficient to fund the future development costs disclosed above. The Corporation typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operations, debt financing and new equity. The Corporation plans to utilize all three sources to meet its future development cost needs.

OIL AND GAS PROPERTIES

The following is a description of the oil and natural gas properties in which the Corporation has an interest and that are material to its operations and activities. The production numbers stated refer to the Corporation's working interest share before deduction of Crown and freehold royalties. Reserve amounts are stated before deduction of royalties based on escalated cost and price assumptions as evaluated in the GLJ Report as at December 31, 2011.

Canada

Amber Area, Alberta

The Amber area is located in Twp 113 -114 and Rge 6 – 8 W6M. The Corporation acquired a 100% working interest in 36,100 acres (56.4 sections) of undeveloped land in June 2011. The land is prospective for Sulphur Point and emerging unconventional resource oil in the Jean Marie and Muskwa. No reserves have been assigned to Strategic in Amber in 2011. The 2012 development program includes the drilling and evaluation of two test wells in Q3/Q4.

Caroline Area, Alberta

Caroline Area is located in west central Alberta and is operated by NAL Resources. The Corporation has a minor working interest (18.5%) in 2 sections. In 2011 the operator drilled one successful horizontal well in the Cardium (16-08) which went on production January 2012. Strategic elected to go penalty on the well which for the Corporation provided similar expected present values with no risk. The well will provide income to the Corporation after reversion. Additional horizontal Cardium locations have been identified.

The Corporation in 2011 produced 19,700 boes or 54 boe/d from this property and GLJ has attributed 72,000 boes of proved reserves and 158,000 boes proved plus probable reserves to this property. There were 3 gross (0.5 net) gas wells on production for the year 2011.

Ferrier Area, Alberta

Ferrier is located in west central Alberta and is operated by Baccalieu Energy. In 2011 the operator recompleted the 10-04 well in the Ellerslie and is now producing approximately 100 mcfd.

The Corporation's share of production from the Ferrier area for the full year 2011 was 19,940 boes or 55 boe/d. The Corporation has 160 (42 net) undeveloped acres in this area. GLJ has attributed 83,000 boes of proved reserves and 156,000 boes of proved plus probable reserves to this property.

Historically, the Corporation entered into a farm out, equalization and participation agreements with another industry partner in 2008. Pursuant to those agreements the Corporation participated in the drilling of six wells. This area is known for wells having multiple pay zones and liquids rich natural gas. There were 4 gross (1.1 net) gas wells and 1 gross (0.3 net) oil wells on production for the year 2011.

Conrad, Alberta

Conrad is located 35 km southwest of Taber, Alberta. Strategic holds a 100% working interest and operates a mature medium gravity oil property at Conrad. There are 16 gross (13.9 net) oil wells and a production facility. The field currently produces 23 degree API oil from the Ellis Member of the Sawtooth Formation (1,000 m in depth) at a total rate of approximately 60 barrels of oil per day. The geological setting for the Sawtooth Formation at Conrad is a series of sands lapping a Mississippian high. Strategic drilled and tied-in wells at 100/14-23 and 102/06-23 in 2010. Production attributed to the Corporation for the full year 2011 from Conrad was 21,883 boes or 60 boe/d. GLJ has attributed 150,000 boes of proved reserves and 221,000 boes of proved plus probable reserves to this property.

Maxhamish, Northeast British Columbia

Maxhamish is located 125 km north of Fort Nelson and is operated by Legacy Oil & Gas. In 2011 Strategic participated in two horizontal wells which were drilled and multi-stage fractured stimulated. Both wells were placed on production late 2011. The property now has 8 producing oil wells (3.5 net to the Corporation). Strategic has a 38.5% working interest in 4,745 acres of developed and 64,709 acres of undeveloped land for a total position of 69,454 acres (26,740 net). The Corporation in 2011 produced 12,582 boes from this property. GLJ has attributed 101,000 boes of proved reserves and 202,000 boes of proved plus probable reserves to this property.

In early 2011, Strategic commissioned GLJ to conduct an independent resource evaluation of the Corporation’s Maxhamish area effective December 31, 2010. This study has assigned discovered petroleum initially-in-place (“DPIIP”) to 13,874 gross acres (22 sections gross lease) of land for a best estimate of 123 MMbbl of oil (48 MMbbl net to Strategic). This represents 6 MMbbl of oil per section gross lease. This assignment is consistent with Strategic’s internal estimate for DPIIP resources for the study area. The DPIIP study is restricted to a 3 mile extension from the existing wells where proven and probable assignment of reserves has been recognized and does not extend over the entire Maxhamish land base. The 13,874 acres represents 20% of Strategic’s Maxhamish land base. There is no certainty that any portion of the estimated DPIIP will be discovered. Further, if discovered, there is no certainty that it will be commercially viable to produce any portion of the estimated PIIP. Additional drilling analysis is required to develop a resource on the property.

The Corporation's internal estimate for PIIP is over 500 MMbbl (192 MMbbl net) of 42 deg API oil on Strategic's lands. Strategic management's internal estimate has projected recovery factors of between 13% to 15% on primary recovery. At 4 wells per section this would yield recoverable volumes of between 150 and 225 Mbbl per well. The same qualifications as to DPIIP as above apply to PIIP.

Historically, Strategic entered into a purchase and sale agreement ("the Agreement") with its partner to acquire from Encana Corporation the remaining 35% working interest in Maxhamish, for a total purchase price of $13.0 million ($5.0 million net to Strategic), in October 2010.

Terms of the Agreement:

1) The acquisition included 21,500 net acres (> 30 sections) of undeveloped land, 7 oil wells (representing 50 boe/d of production net to Strategic), related facilities, an oil pipeline, and a road that connects the area to the year round Liard Highway.

2) The acquisition included rights to extensive 2-D seismic coverage over the area.

3) The acquisition included rights to the Dunvegan zone, providing access to a source of water.

As a result, the farmout agreement with Encana was eliminated providing Strategic with an undivided 38.5% working interest.

The 2012 development program with Legacy as Operator is proceeding and includes:

i) Re-entry and evaluation of one horizontal well;

ii) Contingent on evaluation, the drilling of additional well(s) by the fourth quarter of 2012, with completions to follow; and

iii) Building infrastructure where necessary, including battery, pipelines, etc.

Steen River / Lessard Area, Alberta

The Steen River area assets are located in northwestern Alberta, approximately 60 mile north of the town of High Level, Alberta. Strategic is operator with a 100% working interest in 15,360 (13,973 net) acres of developed and 44,960 (44,533 net) acres of undeveloped land for a total position of 60,320 acres (58,506 net). At year end 2011 the Corporation had 16 oil wells and 10 gas wells producing. Further, the Corporation operates a major gas and oil production facility. The field currently produces 34 degree API oil from the Sulphur Point and Keg River and gas from the Slave Point, Sulphur Point and Keg River. In 2011 the Corporation drilled 7 wells. All wells were cased and 6 were tied in for production with IP's ranging from 50 to 350 boe/d. The 2011 drilling program added approximately 900 boe/d to the Corporation's yearly production. In 2011, the Corporation purchased 27,520 acres of land in Steen River, shot 39 km^2 of 3D seismic, 44 km of 2D seismic, upgraded the production facility and built all weather road access to all major producing wells.

Production attributed to the Corporation in Steen River for 2011 was 205,006 boes. GLJ has attributed 2,464,000 boes of proved reserves and 3,901,000 boes of proved plus probable reserves to this property.

Historically, the Corporation acquired a 5% working interest in December 2007. On December 22, 2010, Strategic purchased Steen River Oil & Gas Ltd. and increased its average producing working interest to 100%. Production from the Steen River area assets at year end 2011 was weighted 82 percent to oil with the balance being natural gas. All production is pipelined to Corporation-owned processing facilities that include a sour service natural gas plant rated to 40 mmcf/d and fluid handling and treating facilities for the oil. Oil sales are then trucked to Rainbow whereas the gas sales are directly tied into the Nova pipeline system at the plant gate. Produced water and acid gas are both disposed of into a water disposal well and an acid gas injection well respectively.

The Lessard asset is located to the East of Steen River, located across the Haywood River and currently is non-producing due to access restrictions. There are numerous oil and gas wells in this area which require a gathering system scheduled for tie-in 2013. GLJ has attributed Lessard with 66,000 boes of proved reserves and 185,000 boes of proved plus probable reserves.

The 2012 development program is proceeding on schedule:

i. In Q1 and Q2 drill 9 wells with infrastructure and all weather roads, where possible, to major producing wells,

ii. Shoot 31 km of additional 2D seismic,

iii. In Q3 and Q4 drill an additional 4 plus wells with infrastructure and all weather roads, where possible, to major producing wells, and

iv. Facility upgrades to expand fluid operating capacity.

Larne Area, Alberta

The Larne area assets are located in north western Alberta and to the east of the Zama Keg River basin. Strategic is operator with a primarily 60% working interest in 9,440 (4,996 net) acres of developed and 17,120 (10,092 net) acres of undeveloped land for a total position of 26,560 acres (15,088 net). The Larne assets include the Larne natural gas field plus several single well pools which produce from the Sulphur Point and Slave Point formations. The Larne assets are 100% weighted toward natural gas with minor associated natural gas liquids. In the Larne area the Corporation owns an interest in 11 gross (7.4 net) producing gas wells and 13 gross (10.2 net) non-producing gas wells.

Production from the Larne assets are treated through a Paramount operated facility located at 1-1-118-2W6 before the gas is then pipelined to a third party owned processing facilities that includes fluid handling, gas processing and compression with a sales gas connection to the Nova pipeline.

Production attributed to the Corporation in Larne for 2011 was 44,118 boes. GLJ has attributed 142,000 boes of proved reserves and 215,000 boes of proved plus probable reserves to this property.

Taber, Alberta

Strategic holds a 75% working interest and operates a mature medium gravity oil property at Taber, in Southern Alberta. There are 13 oil wells and a production facility. The field currently produces 23 degree API oil from the Glauconite Formation (1,000 m in depth) at a total rate of approximately 59 barrels of oil per day net to Strategic. The Glauconite reservoir is consistently clean and highly porous and permeable, with permeabilities greater than 1,000 mD. Typical net oil pays range from 2.0-5.0 metres. Strategic's wells at Taber have a long reserve life and have been producing medium gravity oil at a steady rate for several decades. Production attributed to the Corporation from Taber for 2011 was 21,671 boes or 59 boe/d. GLJ has attributed 98,000 boes of proved reserves and 178,000 boes of proved plus probable reserves to this property. The additional probable reserves at Taber may be obtained through infill drilling and through a comprehensive plan to optimize the water flood currently in place

United States

Pinedale, Wyoming

The Corporation purchased a 22.5% working interest in 640 acres of land located in the Greater Green River Basin in southwest Wyoming in 2008. The target zone of interest is in the Lance formation which has producing zones in the offset Jonah/Pinedale fields. The Corporation has 135 net acres of undeveloped land on this prospect (600 gross acres). The Corporation's share of production from this area for the year 2011 was 2,661 boes or 7 boe/d.

Oil and gas wells

The following table summarizes Strategic's interest as at December 31, 2011 in wells that were producing and non-producing at that time.

	Producing wells				Non-producing wells					
	Oil		Gas		Standing		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	55	43.5	30	21	46	39.4	7	4.9	27	22.5
USA	-	-	2	.5	-	-	-	-	-	-
Total	55	43.5	32	21.5	46	39.4	7	4.9	27	22.5

Notes:
1. "Gross" refers to all wells in which Strategic has a working interest.
2. "Net" refers to the aggregate of the percentage working interests of Strategic in the gross wells before deduction for royalties.

Forward Contracts

The Corporation does not have any outstanding forward contracts.

Properties with No Attributed Reserves

	Gross acres	Net acres	Net acres expiring within one year
Canada	190,749	138,272	7,518
USA	600	135	-
Total	191,349	138,407	7,518

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

The Corporation estimates well abandonment costs area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the GLJ Report (forecast pricing) is $3,641,000, of which $248,000 is estimated to be incurred in the next three financial years.

Tax Horizon

The Corporation was not required to pay income taxes during the year ended December 31, 2011. Taxes payable beyond 2011 will become a function of commodity prices, production volumes, capital expenditures and current tax pools available to offset taxable income. Based on a strategy of re-investing internally generated cash flow in an exploration and development program and based on commodity prices used in the GLJ Report, combined with its current tax pools, the Corporation estimates that it will not be required to pay income taxes until after 2013.

COSTS INCURRED

The following table summarizes the Corporation's property acquisition costs, exploration costs and development costs for the year ended December 31, 2011.

	Property acquisition costs$000			
	Proven properties	**Unproven properties**	**Exploration costs**	**Development costs**
Canada	-	4,117	12,588	29,355
USA	-	-	-	-
Total	**-**	4,117	12,588	29,355

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes Strategic's exploration and development wells completed in the year ending December 31, 2011.

	Gross Wells	**Net wells**	**Net Oil wells**	**Net gas wells**	**Net dry**
Exploratory wells completed					
Canada	3	3	3	-	-
USA	-		-	-	
Development wells completed					
Canada	6	4.8	4.8	-	-
USA	-	-	-	-	-

Most of Strategic's exploration and development activity in the next year will be focused on its properties located in Canada as well as new opportunities.

PRODUCTION ESTIMATES

The following table discloses for each product type the total volume of production estimated by GLJ for 2012 in the estimates of future net revenue from proved reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

	2012 Average Daily Production										Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
Entity Description	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d
Proved Producing																				
Steen River	836	613	0	0	711	600	0	0	955	713	1,303	920	0	0	922	807	0	0	1,457	1,055
Other Properties	111	103	63	60	1,094	962	34	24	390	348	206	194	152	147	1,515	1,331	62	46	672	609
Total: Proved Producing	**947**	**717**	**63**	**60**	**1,805**	**1,561**	**34**	**24**	**1,344**	**1,061**	**1,509**	**1,115**	**152**	**147**	**2,437**	**2,138**	**62**	**46**	**2,129**	**1,664**
Proved Developed Nonproducing																				
Steen River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	411	366	0	0	68	61
Other Properties	0	0	0	0	0	0	0	0	0	0	39	27	0	0	165	147	0	0	66	51
Total: Proved Developed Nonproducing	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39**	**27**	**0**	**0**	**575**	**513**	**0**	**0**	**135**	**112**
Proved Undeveloped																				
Steen River	448	406	0	0	92	84	0	0	463	420	913	660	0	0	180	153	0	0	943	685
Other Properties	0	0	0	0	76	72	0	0	13	12	0	0	0	0	61	53	-1	-1	9	8
Total: Proved Undeveloped	**448**	**406**	**0**	**0**	**168**	**157**	**0**	**0**	**476**	**433**	**913**	**659**	**0**	**0**	**240**	**207**	**-1**	**-1**	**952**	**693**
Total Proved																				
Steen River	1,284	1,020	0	0	803	684	0	0	1,418	1,134	2,216	1,580	0	0	1,512	1,327	0	0	2,468	1,801
Other Properties	111	103	63	60	1,170	1,034	34	25	403	360	244	221	152	147	1,740	1,531	61	45	747	668
Total: Total Proved	**1,395**	**1,123**	**63**	**60**	**1,973**	**1,718**	**34**	**25**	**1,821**	**1,494**	**2,461**	**1,801**	**152**	**147**	**3,252**	**2,858**	**61**	**45**	**3,215**	**2,469**
Total Probable																				
Steen River	324	289	0	0	146	127	0	0	349	310	1,263	882	0	0	1,018	871	0	0	1,432	1,027
Other Properties	26	22	2	1	73	64	6	6	46	40	224	200	73	70	1,649	1,455	51	40	623	552
Total: Total Probable	**350**	**312**	**2**	**1**	**219**	**192**	**6**	**6**	**394**	**350**	**1,486**	**1,082**	**73**	**70**	**2,666**	**2,326**	**51**	**40**	**2,055**	**1,579**
Total Proved Plus Probable																				
Steen River	1,608	1,309	0	0	950	811	0	0	1,767	1,444	3,479	2,462	0	0	2,530	2,198	0	0	3,901	2,828
Other Properties	137	1276	64	61	1,243	1,098	41	30	449	400	468	421	226	217	3,389	2,986	112	84	1,370	1,220
Total: Total Proved Plus Probable	**1,745**	**1,435**	**64**	**61**	**2,193**	**1,909**	**41**	**30**	**2,215**	**1,844**	**3,947**	**2,883**	**226**	**217**	**5,919**	**5,184**	**112**	**84**	**5,271**	**4,048**

PRODUCTION HISTORY

The following tables disclose, on a quarterly basis for the year ended December 31, 2011, the Corporation's share of average daily production volumes, prior to royalties, prices received, royalties paid, production costs incurred and net backs on a per boe basis.   Average daily production

	Average daily production for the three months ended			
	March 31 2011	**June 30 2011**	**September 30 2011**	**December 31 2011**
Canada				
Oil (Bbls/d)	537	496	560	912
Natural gas (Mcf/d)	1,315	2,072	1,877	1,679
NGLs (Bbls/d)	27	35	35	31
United States				
Oil (Bbls/d)	-	-	-	-
Natural gas (Mcf/d)	43	44	39	45
NGLs (Bbls/d)	-	-	-	-
Total (boe/d)	790	884	914	1,230

Average prices received, royalties paid, production costs and net back

	Three months ended			
	March 31 2011	**June 30 2011**	**September 30 2011**	**December 31 2011**
Canada				
Prices $				
Oil - per Bbl	83.07	98.12	84.26	94.43
Natural gas - per Mcf	3.94	4.07	3.86	3.36
NGLs - per Bbl	47.96	67.18	53.75	52.77
Per Boe $	65.27	67.85	62.04	76.36
Royalties paid per Boe $	18.06	16.32	8.78	17.34
Production costs per Boe $	48.88	34.14	25.88	33.44
Net back per Boe $	(1.67)	17.39	27.38	25.58
United States				
Prices $				
Oil - per Bbl	-	-	-	-
Natural gas - per Mcf	3.33	5.04	6.21	3.66
NGLs - per Bbl	-	-	-	-
Per Boe $	19.99	30.22	34.08	21.95
Royalties paid per Boe $	5.24	4.96	7.01	4.66
Production costs per Boe $	9.15	8.71	4.29	8.47
Net back per Boe $	5.60	16.55	22.78	8.82

Production Volume by Field

The following table discloses for each important field, and in total, the Corporation's production volumes for the financial year ended December 31, 2011 for each product type.

	Light and Medium Crude (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Caroline	1,545	36,460	5,565
Conrad	21,883	-	-
Ferrier	969	78,350	5,913
Maxhamish	12,410	1,029	167
Steen River	168,897	216,655	-
Larne	1,417	256,204	-
Bistcho	100	45,361	-
Taber	21,671	-	-
Other - US	55	15,636	-
Total	228,947	649,695	11,645

DEVELOPMENTS SINCE DECEMBER 31, 2011

The Corporation has approved a capital budget for 2012 of $60 million that is expected to provide significant growth in crude oil production in 2012. The capital program includes $35 million focused on the crude oil program at Steen River. The remainder of the capital program will target optimizing the Corporation's assets with production optimization as well as investment in land and seismic. The Corporation’s drilling plan includes an estimated 20 (17 net) wells and is expected to provide 2012 average production of 2,400 boe/d and generate funds flow of approximately $34-38 million.

In Q1, 2012 the Corporation drilled and cased nine wells in Steen River. At the end of the Q1 two of the nine wells were on production with an additional five wells on production in April. The remaining two wells will be on production in May and July, respectively.

FORMS 51-101F2 AND 51-101F3

Form 51-101F2, Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Form 51-101F3, Report of Management and Directors on Oil & Gas Disclosure for the period ending December 31, 2011 can both be found on www.sedar.com.