LONG RUN EXPLORATION LTD.

2012 ANNUAL REPORT

Management's Responsibility for Financial Reporting

The accompanying financial statements and all information in this report are the responsibility of management. Management has prepared the financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and, when necessary, management has made informed judgments and estimates in accounting for transactions that were not complete at the statement of financial position date. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances as indicated in the notes to the financial statements. Financial information contained elsewhere in this report has been prepared and reviewed by management to ensure it is consistent with the financial statements.

Management has established systems of internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards.

The Audit and Reserves Committees are appointed by the Board of Directors, and are comprised of directors that are not employees of the Corporation. The Audit Committee meets regularly with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is discharging its responsibilities, and to review the financial statements and the external auditors' report. The Board of Directors has approved the financial statements.

Bill Andrew
Chairman and Chief Executive Officer

Shivon M. Crabtree
Vice President Finance and
Chief Financial Officer

March 7, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Long Run Exploration Ltd.

We have audited the accompanying financial statements of Long Run Exploration Ltd. (formerly WestFire Energy Ltd.), which comprise the statement of financial position as at December 31, 2012, and the statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for the year ended December 31, 2012, and a summary of significant accounting policies and other explanatory information.

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

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

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

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

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Long Run Exploration Ltd. as at December 31, 2012 and its financial performance and its cash flows for the year ended December 31, 2012 in accordance with International Financial Reporting Standards.

Other Matters
The financial statements of Long Run Exploration Ltd. (formerly WestFire Energy Ltd.) as at and for the year ended December 31, 2011 were audited by another auditor who expressed an unqualified opinion on those financial statements on March 26, 2012.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada
March 7, 2013

Management's Discussion and Analysis

This Management's Discussion & Analysis ("MD&A") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Long Run Exploration Ltd. ("Long Run" or the "Corporation"), formerly WestFire Energy Ltd. ("WestFire"), for the year ended December 31, 2012, with comparisons to the year ended December 31, 2011. The MD&A has been prepared by management and should be read in conjunction with the audited financial statements for the years ended December 31, 2012 and December 31, 2011.

Petroleum and natural gas reserves and volumes are converted to a common unit of measure on a basis of six thousand cubic feet (Mcf) of gas to one barrel (Bbl) of oil. BOEs may be misleading, particularly if used in isolation. The forgoing conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of six to one, utilizing a conversion on a six to one basis may be misleading as an indication of value.

Amounts are shown in Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes.

This MD&A is based on information available as of, and is dated, March 7, 2013.

Non-GAAP Measurements

The MD&A contains terms commonly used in the oil and gas industry, such as funds flow from operations, funds flow from operations per share, and operating netback. These terms are not defined by International Financial Reporting Standards (IFRS) and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with IFRS as an indicator of Long Run's performance. Management believes that funds flow from operations is a useful financial measurement which assists in demonstrating the Corporation's ability to fund capital expenditures necessary for future growth or to repay debt. Long Run's determination of funds flow from operations may not be comparable to that reported by other companies. All references to funds flow from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures. The Corporation calculates funds flow from operations per share by dividing funds flow from operations by the weighted average number of common shares outstanding.

Long Run uses the term net debt in the MD&A and presents a table showing how it has been determined. This measure does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies.

Forward-Looking Statements

Statements that are not historical facts may be considered forward looking statements, including management's assessment of future plans and operations, development plans, drilling plans and the timing thereof, enhanced recovery potential, method of financing of capital expenditures, the expectation that the Corporation will not pay income tax in 2013, the effect of certain hedges, and the expected continued volatility in commodity prices and stock markets and the effects thereof.

These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Corporation's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, Long Run's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manor; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Long Run's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at Long Run's website (www.longrunexploration.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Long Run does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

FINANCIAL AND OPERATING HIGHLIGHTS

	Year ended December 31		
	2012	**2011**	**2010**
Financial			
($000s except per share amounts)			
Petroleum and natural gas revenue	276,605	142,822	43,432
Funds flow from operations [1]	128,719	74,666	20,115
Per share – basic	1.41	1.18	0.54
Per share – diluted	1.41	1.17	0.54
Net income (loss)	(42,652)	(52,667)	772
Per share – basic	(0.47)	(0.83)	0.02
Per share – diluted	(0.47)	(0.83)	0.02
Capital expenditures	210,410	179,995	72,007
Disposals of oil and gas properties	(178,241)	(1,817)	(6,579)
Total assets	1,193,272	665,811	243,503
Bank loan	261,173	124,000	8,089
Working capital deficiency, excluding financial derivatives and bank loan	31,950	753	13,918
Total non-current financial liabilities, excluding bank loan	12,155	5,369	465
Shareholders' equity	585,682	450,494	195,265
Weighted average shares outstanding			
Basic	91,126,249	63,141,989	37,009,179
Diluted	91,126,249	63,555,607	37,168,996
Operating			
Average daily production			
Light oil (Bbl/d)	6,554	2,546	756
Heavy oil (Bbl/d)	1,015	531	368
NGLs (Bbl/d)	1,007	762	104
Natural gas (Mcf/d)	27,679	11,822	7,707
Total (BOE/d)	13,189	5,809	2,513
Average selling prices [2]			
Light oil ($/Bbl)	81.15	93.65	75.80
Heavy oil ($/Bbl)	61.37	67.68	60.91
NGLs ($/Bbl)	72.28	83.54	58.52
Natural gas ($/Mcf)	2.80	3.76	4.30
Total ($/BOE)	57.30	67.36	47.35
Average selling prices, after financial derivative contracts [3]			
Crude oil ($/Bbl)	79.84	87.03	71.45
Natural gas ($/Mcf)	3.23	4.13	5.03

[1] *See "Non-GAAP Measurements"*
[2] *The average prices reported are prior to financial derivatives and transportation charges*
[3] *The average prices reported are after financial derivatives and prior to transportation charges*

In the fourth quarter, WestFire and Guide Exploration Ltd. ("Guide") completed an all share merger transaction. The management team of Guide is leading the renamed Long Run. Long Run is focusing on core properties in the Peace River area and Edmonton area of Alberta. Short to medium term development will focus on Montney oil projects at Peace River and Viking oil projects at Redwater. On a land base of more than 1.8 million net acres, Long Run is actively exploring new concepts while continuing to drive development and growing production in our core areas. Over the long term, it is our intention to build an exploration company with a balanced oil and gas portfolio that focuses on resource plays in western Canada.

Total petroleum and natural gas revenue, before royalties and financial derivatives, was $276.6 million in 2012, an increase of $133.8 million from $142.8 million in 2011. The year over year benefit of higher production volumes for all products in 2012 offset the impact of lower commodity prices.

Crude oil and NGL production volumes of 8,576 Bbl/d in 2012 increased 123% or 4,737 Bbl/d from 3,839 Bbl/d in 2011. Light oil volumes increased by 157% year over year. The increase in crude oil volumes reflects the impact of new wells drilled and the business combination with Guide, completed on October 23, 2012 (the "Guide Arrangement").

Natural gas production averaged 27.7 Mmcf/d in the year ended December 31, 2012, compared to 11.8 Mmcf/d in the prior year. The 135% increase reflects the impact of production from the Guide properties commencing on October 23, 2012.

Crude oil prices, before transportation and financial derivative contracts, decreased 12% in 2012 to $78.50/Bbl from $89.21/Bbl in 2011. The average price for natural gas, before transportation and financial derivative contracts, was $2.80/Mcf in 2012, 26% lower than the $3.76/Mcf price received in 2011.

Realized gains on financial derivative contracts were $8.1 million in 2012, compared to a realized loss on financial derivative contracts of $0.9 million in 2011. The $3.7 million gain realized on crude oil derivatives and the $4.4 million gain realized on natural gas derivative contracts in 2012 raised the effective crude oil and natural gas prices received during the year by $1.34/Bbl and $0.43/Mcf, respectively.

Net general and administrative expenses increased $26.2 million in 2012 to $36.7 million, reflecting transaction and employee costs related to the Guide Arrangement of $20.2 million, as well as higher salary and employee costs.

Funds flow from operations of $128.7 million in the year ended December 31, 2012 was $54.0 million or 72% higher than the funds flow of $74.7 million recorded in 2011.

The $42.7 million net loss incurred during 2012 included a $144.1 million impairment of property and equipment, partially offset by a $75.8 million gain on the disposal of assets, including a $73.3 million gain recorded on the sale of properties in west central Saskatchewan in December 2012.

On October 23, 2012, the Corporation completed the Guide Arrangement and issued $171.1 million of Common Share consideration in exchange for all of the issued and outstanding shares of Guide. The former Guide shareholders received a total of 42.6 million Common Shares, valued on the closing date of the transaction at $4.02 per share.

Results of Operations

Year ended December 31	2012		2011	
	4,827,242 BOE		2,120,285 BOE	
	$000s	$/BOE	$000s	$/BOE
Revenues	276,605	57.30	142,822	67.36
Realized gain (loss) on financial derivatives	8,149	1.69	(852)	(0.40)
Royalties	(38,610)	(8.00)	(19,089)	(9.00)
GCA[1]	9,514	1.97	2,248	1.06
Transportation costs	(9,975)	(2.06)	(2,680)	(1.26)
Operating costs	(70,328)	(14.57)	(34,741)	(16.39)
Net	**175,355**	**36.33**	**87,708**	**41.37**
G&A, excluding non-cash deferred compensation	(36,734)	(7.61)	(10,460)	(4.93)
Interest costs	(9,005)	(1.87)	(2,295)	(1.08)
Exploration expenses	(230)	(0.05)	-	-
Capital and other taxes	(667)	(0.14)	(287)	(0.14)
Funds flow from operations[2]	**128,719**	**26.66**	**74,666**	**35.22**

[1] *GCA means Gas Cost Allowance*
[2] *See "Non-GAAP Measurements"*

Petroleum and Natural Gas Revenue *(before royalties)*

Year ended December 31	2012		2011	
	$000s	%	$000s	%
Light oil	194,589	70	87,013	61
Heavy oil	22,799	8	13,121	9
NGLs	26,671	10	23,220	17
Natural gas	28,268	10	16,098	11
Sulphur	4,115	2	3,167	2
Royalty income	163	-	203	-
Total	**276,605**	**100**	**142,822**	**100**

Revenues for the year ended December 31, 2012 were $276.6 million, compared to $142.8 million during the same period of the prior year. Crude oil and natural gas revenues increased $117.3 million and $12.2 million, respectively, in 2012 compared to 2011. The increased revenues reflect higher oil and natural gas production volumes, partially offset by lower crude oil and natural gas prices, in 2012.

Crude oil and NGL revenues were 88% of total revenues in 2012 compared to 87% of total revenues for the year ended December 31, 2011.

Production

	Year ended December 31			
	2012		2011	
		%		%
Light oil (Bbls/d)	6,554	50	2,546	44
Heavy oil (Bbls/d)	1,015	8	531	9
NGLs (Bbls/d)	1,007	7	762	13
Natural gas (Mcf/d)	27,679	35	11,822	34
BOE/d (6:1)	**13,189**	**100**	**5,809**	**100**

Production averaged 13,189 BOE/d during 2012, an increase of 127% from the average 2011 production of 5,809 BOE/d. By product, production volumes increased as follows: light oil production by 157%, heavy oil production by 91%, natural gas liquids production by 32% and natural gas production by 134%.

In addition to volumes from new wells drilled, the production increase during the year ended December 31, 2012 includes the impact of the Viking asset acquisition on December 9, 2011 and the Guide Arrangement on October 23, 2012.

Commodity Pricing and Marketing

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility and improving netback cash flows, Long Run has entered into several natural gas and crude oil financial contracts. Long Run's current policy allows for hedging up to a maximum of 75% of the average daily production, by product after royalties, for a term of not more than 36 months.

The Corporation has the following financial contracts in place as at December 31, 2012:

Natural Gas:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	3,000 GJ/d	CDN $2.80 - $3.40/GJ
January 1, 2013 – December 31, 2013	7,000 GJ/d	CDN $3.15 - $3.60/GJ
Fixed Price:		
January 1, 2013 – October 31, 2013	5,000 GJ/d	CDN $4.20/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.00/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.50/GJ
January 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $3.60/GJ
April 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $4.05/GJ
Call Swaption:		
January 1, 2014 – December 31, 2014	10,000 GJ/d	CDN $4.00/GJ

Crude Oil:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.25/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$96.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $98.00-$102.00/Bbl
Fixed Price:		
January 1, 2013 – December 31, 2013	600 Bbl/d	WTI CDN $97.05/Bbl
January 1, 2013 – December 31, 2013	1,600 Bbl/d	WTI CDN $100.30/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI US$85.00/Bbl
Calls:		
January 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl
January 1, 2013 – December 31, 2013	73 Bbl/d	WTI US $100.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $100.00/Bbl
Call Swaptions:		
January 1, 2014 – August 31, 2014	980 Bbl/d	WTI US $85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$90.00/Bbl

Interest Rate Swap:	
Notional Amount CAD $75 million	Term: February 6, 2012 – January 5, 2014
Fixed rate 1.190% - Floating rate is reset against CAD-BA-CDOR monthly	

Electricity:	Volume	Pricing
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $67.75 MW/h
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $54.35 MW/h
January 1, 2015 – December 31, 2016	3.0 MW/h	CDN $49.50 MW/h

During 2012, Long Run recorded realized gains of $8.1 million on financial contracts, compared to a loss of $0.9 million in 2011. Certain oil hedges were unwound in October 2012 for proceeds of $2.4 million,

and spot prices for both oil and natural gas in 2012 were lower than the prices Long Run had secured using financial contracts.
Based on the mark to market value at December 31, 2012, an unrealized gain on financial contracts of $7.5 million was recorded in 2012, compared to an unrealized loss on financial contracts of $3.9 million in 2011. If the contracts were unwound at December 31, 2012, the Corporation would pay a net amount of $6.0 million.

Included in petroleum and natural gas revenue for the year ended December 31, 2012 is $0.3 million of net revenue related to buying and selling natural gas on a daily compared to monthly index.

Subsequent to December 31, 2012 the Corporation entered into the following financial derivative contracts:

Crude Oil:	Volume	Pricing
Costless Collars:		
February 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $90.00-$102.00/Bbl
Fixed Price:		
April 1, 2013 – December 31, 2013	1,000 Bbl/d	WTI CDN $96.75/Bbl
Calls:		
April 1, 2013 – December 31, 2013	200 Bbl/d	WTI US $85.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $85.00/Bbl
January 1, 2015 – December 31, 2015	500 Bbl/d	WTI US $85.00/Bbl

Subsequent to December 31, 2012, the Corporation cancelled the following financial derivative contract:

Crude Oil:	Volume	Pricing
Calls:		
April 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl

Prices ***(prior to financial derivatives and transportation charges)***

	Year ended December 31	
	2012	**2011**
Light oil ($/Bbl)	81.15	93.65
Heavy oil ($/Bbl)	61.37	67.68
NGLs ($/Bbl)	72.28	83.54
Natural gas ($/Mcf)	2.80	3.76
Sulphur ($/tonne)	142.26	170.71

Prices realized in 2012 were lower for all products than those realized in 2011. Light oil prices decreased by 13%, heavy oil prices decreased by 9%, NGL prices decreased by 13%, natural gas prices decreased by 26%, and the average price received for sulphur decreased by 17%.

The average light oil price received by the Corporation in 2012 was approximately $5.00/Bbl lower than the weighted average Edmonton light oil price, compared to a decrease to the weighted average Edmonton light oil price of approximately $2.00/Bbl in 2011. Heavy oil prices received were approximately $25.00/Bbl and $27.00/Bbl lower than the weighted average Edmonton light oil price in 2012 and 2011, respectively.

Long Run's policy to hedge a portion of its crude oil and natural gas production impacted funds flow in the 2012. For natural gas, Long Run's financial contracts increased the average realized price by \$0.43/Mcf from \$2.80/Mcf to \$3.23/Mcf, before transportation. Crude oil hedges increased the average price received in 2012 by \$1.34/Bbl, from \$78.50 to \$79.84 per barrel.

Crude Oil Prices

Year ended December 31	**2012**		**2011**	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	217,475	78.50	100,188	89.21
Realized financial contracts	3,723	1.34	(2,449)	(2.18)
Transportation	(7,213)	(2.60)	(2,194)	(1.96)
Net crude oil	**213,985**	**77.24**	**95,545**	**85.07**

Natural Gas Prices

Year ended December 31	**2012**		**2011**	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	28,338	2.80	16,240	3.76
Realized financial contracts	4,353	0.43	1,597	0.37
Transportation	(2,201)	(0.22)	(416)	(0.09)
Net natural gas	**30,490**	**3.01**	**17,421**	**4.04**

NGL Prices

Year ended December 31	**2012**		**2011**	
	\$000s	\$/Bbl	\$000s	\$/Bbl
NGL	26,677	72.38	23,227	83.54
Transportation	(176)	(0.48)	(70)	(0.25)
Net NGL	**26,501**	**71.90**	**23,157**	**83.29**

In addition to the above, the Corporation recorded sulphur revenue, net of transportation, of \$3.7 million in the year ended December 31, 2012, compared to \$3.2 million in 2011.

Production by Property

Year ended December 31

	2012				**2011**			
	Gas Mcf/d	Oil & NGLs Bbl/d	BOE/d	%	Gas Mcf/d	Oil & NGLs Bbl/d	BOE/d	%
Redwater	8,459	4,393	5,803	44	4,946	2,219	3,042	53
Peace	4,280	969	1,682	13	-	-	-	-
Boyer	3,349	-	558	4	-	-	-	-
Kaybob	8,041	877	2,217	17	5,543	716	1,640	28
Plato – sold in 2012	612	1,262	1,364	10	664	374	485	8
Other areas	2,938	1,075	1,565	12	669	530	642	11
	27,679	**8,576**	**13,189**	**100**	**11,822**	**3,839**	**5,809**	**100**

Redwater Area – East Central Alberta

Redwater Area production in 2012 averaged 4,393 Bbl/d of oil and NGLs, an increase of 98% from 2,219 Bbl/d in 2011. Natural gas production averaged 8.5 Mmcf/d in 2012, an increase of 71% from 4.9 Mmcf/d in 2011.

The Redwater Area is located approximately 50 kilometres northeast of the city of Edmonton, Alberta. Long Run's activities in the Redwater Area are directed primarily toward light oil in the Viking formation. Development is occurring using horizontal drilling at a density of up to 16 wells per section. Long Run will evaluate the potential for enhanced recovery within this play during 2013.

Long Run processes, operates, and transports substantially all of its production in the Redwater area.

During 2012, Long Run drilled a total of 63 (59.4 net) wells in the Redwater area. Up to a total of 70 (67.4 net) wells are planned for 2013.

Peace Area – Northwest Alberta

As this area came into Long Run via the Guide Arrangement, the financial statements of Long Run reflect operations in the Peace Area commencing on October 23, 2012. Oil and NGL production averaged 5,066 Bbl/d of oil and NGLs during the period October 23, 2012 to December 31, 2012, or 969 Bbl/d averaged over 2012. During the period October 23, 2012 to December 31, 2012 natural gas production averaged 22.4 Mmcf/d, or an annual average of 4.3 Mmcf/d.

The majority of Long Run's production in this area comes from the Triassic Montney formation at Normandville and Girouxville, near the town of Falher, Alberta. Long Run has identified, delineated, and initiated development of a fairway that is approximately 30 miles long and six miles wide. Development will occur via horizontal drilling with a density of between four and eight wells per section, targeting oil. Enhanced recovery potential also exists in this field and will be evaluated during 2013.

Long Run operates, transports, and processes substantially all of its production in the Peace Area.

Subsequent to October 23, 2012, Long Run drilled a total of 5 (5.0 net) wells in the Peace area during 2012. Up to a total of 50 (50.0 net) wells are planned for 2013.

Royalties

Year ended December 31	2012	2011
($000s, except as indicated)		
Crown	21,129	12,347
Freehold	12,419	4,901
GORR and other	5,062	1,841
Gross royalties	**38,610**	**19,089**
GCA	(9,514)	(2,248)
Net royalties	**29,096**	**16,841**
% of revenue	**14.0**	**13.4**
% of revenue net of GCA	**10.5**	**11.8**

Gross royalties were 14.0% of revenues during 2012, compared to 13.4% for the same period in 2011. By product, gross royalties were 12.1% for light oil, 11.0% for natural gas, 14.1% for heavy oil, and 29.6% for liquids. For the year ended December 31, 2011, gross royalties were 10.2% for light oil, 12.8% for natural gas, 11.4% for heavy oil, and 25.9% for liquids.

Total royalties, net of GCA, were 10.5% during 2012, compared to 11.8% during 2011.

Gain on Farm-Outs

During 2011, the Corporation entered into a farm-out agreement with an industry partner (the "Farmee") on lands in the west central area of Saskatchewan, whereby the Farmee had committed to drill, complete and equip or abandon thirty horizontal wells on or before December 31, 2012. The Farmee was obligated to pay seventy-five percent of the costs of the wells to earn a fifty percent working interest in the farm-out lands. The agreement further stipulated that the Farmee must drill, complete, and equip or abandon fifteen of the commitment wells on or before December 31, 2011 in order to retain the lands under this agreement. The Farmee had satisfied the 2011 commitment by December 31, 2011. The Corporation received $5.0 million as initial consideration under this agreement, which was recorded as deferred compensation on the statement of financial position as of December 31, 2011.

Upon completion of the farm-out commitment during 2012, the Corporation recognized a gain of $11.4 million, representing 33% of the accumulated costs of the Farmee during the earning period plus the $5.0 million of initial consideration received, less fifty percent of the original cost of the farm-out lands prior to the farm-out arrangement .

Gains on Disposals of Assets

Any gain or loss on the disposal of assets, including oil and natural gas properties, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in the statement of earnings. During the year ended December 31, 2012 gains on disposal of assets of $75.8 million were recognized (December 31, 2011 – a net loss of $0.2 million).

The Corporation disposed of properties in west central Saskatchewan in December 2012 for gross proceeds of $175.9 million, net of adjustments and transaction fees, resulting in a net gain on disposal of $73.3 million. These properties were producing approximately 1,900 BOE/d at the time of the sale.

Operating Costs

Operating costs were $70.3 million during 2012 compared to $34.7 million during 2011. Operating costs of $14.57/BOE during the year ended December 31, 2012, decreased 11% from $16.39/BOE in the year ended December 31, 2011. The lower operating costs per BOE in 2012 reflects the benefits of increased production from lower cost areas, including Redwater and Peace, as well as a reduction in the year over year operating costs per BOE at Plato due to higher production in the area.

General and Administration Expenses

Year ended December 31	**2012**		**2011**	
	$000s	$/BOE	$000s	$/BOE
Gross G&A, excluding costs related to the Guide Arrangement	23,891	4.95	14,373	6.78
Transaction and employee costs related to the Guide Arrangement	20,175	4.18	-	-
Gross G&A	44,066	9.13	14,373	6.78
Capitalized overhead	(6,704)	(1.39)	(3,501)	(1.65)
Overhead recoveries	(628)	(0.13)	(362)	(0.17)
Net	**36,734**	**7.61**	**10,510**	**4.96**

Gross general and administration (G&A) expenses increased $29.7 million in 2012 compared to 2011. The increase reflects the $20.2 million of transaction and employee costs related to the Guide Arrangement and increased salary, office space and employee costs. Transaction and employee costs related to the Guide Arrangement include severance and employee costs, advisor fees, legal and other expenses.

Share-Based Compensation

Share-based compensation was a non-cash expense of $6.4 million during 2012, of which $0.9 million was capitalized. During the year ended December 31, 2011, share-based compensation expense was $4.8 million, of which $1.1 million was capitalized.

All of the unexercised options outstanding on October 23, 2012 were cancelled, in conjunction with the Guide Arrangement, resulting in an acceleration of share-based compensation expense of $2.7 million.

In December 2012, the Corporation granted 8,042,000 stock options at an average exercise price of $4.49 per share, having an average fair value of $1.37 per option, all of which were outstanding at December 31, 2012.

Interest

Interest expense was $9.0 million during 2012, compared to $2.3 million recorded in the prior year, due to an increase in the average debt balance outstanding during the year. As at December 31, 2012, an amount of $261.2 million was drawn against the Corporation's credit facilities, compared to $124.0 million at December 31, 2011.

Exploration Expenses

Expenditures incurred before the Corporation has obtained the legal right to explore are expensed in the statement of earnings. Seismic expenditures of $0.2 million, relating to lands not owned by the Corporation, were expensed in the year ended December 31, 2012 (December 31, 2011 - $Nil).

Accretion

Accretion expense on the Corporation's decommissioning liabilities was $2.0 million during 2012, compared to $0.9 million in 2011. Decommissioning liabilities increased $190.9 million during the year to $233.1 million at December 31, 2012. The increase of reflects the Guide Arrangement and a change in cost estimates at December 31, 2012.

Derecognition Expense

The carrying amount of an asset is derecognized on disposal or when future economic benefits are no longer expected from its use or disposal, with the resulting gain or loss recognized in the statement of earnings. During 2012, costs of $0.8 million associated with expiring land leases were expensed, compared to $Nil expensed during 2011.

Depletion and Depreciation

Depletion and depreciation expense was $121.6 million or $25.18/BOE during 2012, compared to $54.3 million or $25.61/BOE for 2011. Petroleum and natural gas reserves were estimated by independent reserve evaluators as at December 31, 2012.

Capital expenditures of $31.4 million (December 31, 2011 - $Nil) related to undeveloped land have been excluded from, and $562.4 million (December 31, 2011 - $476.7 million) of future development costs have been added into, the cost bases for depletion purposes. Estimated residual values of $50.1 million have been excluded from costs subject to depletion (December 31, 2011 - $10.8 million).

In addition, as at December 31, 2012, the Corporation had $20.9 million of exploration and evaluation assets, comprised primarily of undeveloped land, which are not depleted (December 31, 2011 - $Nil).

Impairment of Property and Equipment

For the year ended December 31, 2012, the Corporation recorded an impairment expense of $144.1 million related to property and equipment as a non-cash charge to earnings, compared to an impairment of $73.6 million recorded in 2011. During the year ended December 31, 2012 impairments resulted primarily from a weakening of the future price forecasts, in addition to a reduction of the estimated reserve volumes at Kaybob. Of the $73.6 million impairment recorded at December 31, 2011, approximately ninety percent was attributable to the natural gas weighted Kaybob CGU, with the balance attributed to the Alberta heavy oil weighted CGU.

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in price forecasts, production costs or recovery rates may change the economic value of reserves, resulting in additional impairments or reversals of impairments in the future.

Impairment of Goodwill

The Corporation reviewed the valuation of goodwill as of December 31, 2012 and determined that the recoverable amount had declined below the carrying value. Based upon this review, an impairment of goodwill of $2.0 million was recorded as a non-cash charge to earnings as of December 31, 2012.

Capital and Deferred Taxes

The 2012 and 2011 current tax provisions of $0.7 million and $0.3 million, respectively, relate to Saskatchewan capital and resource tax, and were based upon revenues earned in Saskatchewan. It is not expected that Long Run will pay income taxes in 2013.

The 2012 deferred income tax recovery was $10.0 million on a loss before tax of $52.0 million. A deferred income tax recovery of $9.4 million on a loss before tax of $61.7 million was recorded in 2011.

The $116.7 million increase in the deferred tax asset during the year ended December 31, 2012 includes the $107.1 million deferred tax asset recorded upon completion of the Guide Arrangement.

Capital Expenditures

Exploration and evaluation assets, property and equipment, net	$000s
Balance at December 31, 2011	585,826
Additions	210,410
Guide Arrangement	505,802
Disposals	(110,525)
Decommissioning liability additions	28,392
Capitalized share-based and deferred compensation	839
Derecognition expense	(784)
Non-monetary transactions	6,373
Depletion and depreciation	(121,568)
Impairment of property and equipment	(144,116)
Balance at December 31, 2012	**960,649**

Year ended December 31	2012		2011	
	$000s	%	$000s	%
Land	15,157	7	41,195	23
Geological and geophysical	3,612	2	4,543	3
Drilling and completion	149,293	71	102,344	57
Plant and facilities	43,160	21	31,292	17
Inventory	(1,313)	(1)	228	-
Other assets	501	-	393	-
Exploration & evaluation assets, property & equipment expenditures	**210,410**	**100**	**179,995**	**100**

The Corporation drilled 132.0 (120.4 net) oil wells during the year, with a 100% success rate.

During December 2012, the Corporation disposed of properties in west central Saskatchewan for proceeds of $175.9 million, after adjustments and transaction fees. Production attributable to the properties sold averaged approximately 1,400 BOE/d during the twelve months ended December 31, 2012, comprised primarily of oil and NGLs.

Liquidity and Capital Resources

As at December 31	2012	2011
($000s)		
Bank debt	261,173	124,000
Working capital deficiency[1]	31,950	753
Total net debt [2]	**293,123**	**124,753**

[1] *Excludes fair value of financial derivatives and bank loan*
[2] *See "Non-GAAP Measurements"*

The $168.4 million increase in net debt during 2012 includes the $264.4 million of net debt assumed upon completion of the Guide Arrangement, offset by the activity outlined in the capital program funding table below.

Funding of Capital Program

Year ended December 31	2012	2011
($000s)		
Funds flow from operations [1]	128,719	74,666
Disposals of properties	178,241	1,817
Change in bank debt	(103,859)	63,113
Issuance of common shares, net of costs	277	40,961
Cash acquired on corporate acquisition	-	3,679
Deferred compensation on farm-out agreement	-	5,000
Decrease (increase) in cash	3,778	(7,581)
Change in working capital and other	3,254	(1,660)
Exploration & evaluation assets, property & equipment investing activity	**210,410**	**179,995**

[1] *See "Non-GAAP Measurements"*

The Corporation has available credit facilities of $450.0 million, consisting of a $420.0 million revolving syndicated facility and a $30.0 million operating facility. The credit facilities terminate on May 31, 2015 unless extended. Total borrowings permitted under these facilities cannot exceed the borrowing base which is determined by the lenders, and occurs semi-annually or upon the occurrence of a material adverse effect. The borrowing base established by the syndicate at December 31, 2012 is $430.0 million.

Security for the credit facilities includes a demand debenture for $1.0 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Corporation. At December 31, 2012, an amount of $261.2 million was drawn against the credit facilities (December 31, 2011 - $124.0 million).

The credit facilities bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances require the payment of a stamping fee equal to a margin. The margins range from 1.00% per annum to 4.00% per annum, based upon the Corporation's debt to EBITDA ratio. For the year ended December 31, 2012, the effective interest rate, including standby and other fees, was 4.6% (December 31, 2011 – 5.5%).

The level of the borrowing base is determined by the bank syndicate based upon their review of, among other things, the Corporation's reserves and the value thereof, utilizing commodity prices determined by the bank syndicate which may be different than those utilized by the Corporation's independent reserve evaluator.

The Corporation believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and to undrawn committed credit facilities to meet current spending forecasts.

Sensitivity Analysis

The following table shows sensitivities to 2013 budgeted funds flow from operations as a result of fluctuations in product prices, production volumes, and interest rates.

Change to annual funds flow from operations[3]	Change	$000s	$/share[2]
Price per barrel of oil (US$ WTI)[1]	$1.00	1,800	0.01
Price per mcf of natural gas (CDN$ AECO)	$0.10	1,100	0.01
Oil production volumes	100 Bbl/d	1,900	0.02
Gas production volumes	1 Mmcf/d	200	0.00
Interest rate on debt	1%	2,100	0.02

[1] *After adjustment for estimated royalties*

[2] *Based on Common Shares and Non-Voting Convertible Shares outstanding at December 31, 2012*

[3] *Table is based on budgeted 2013 production volumes*

Contractual Obligations

Contractual obligations as at December 31, 2012 are as follows:

($000s)	Total	2013	2014	2015	2016	2017	Thereafter
Bank loan	261,173	261,173	-	-	-	-	-
Operating leases	11,884	3,003	3,076	2,672	2,089	1,044	-
Firm transportation agreements	5,715	3,167	2,030	437	81	-	-
Vehicle leases	113	113	-	-	-	-	-
Capital commitments	9,374	9,374	-	-	-	-	-
Total	288,259	276,830	5,106	3,109	2,170	1,044	-

At December 31, 2012 the Corporation is committed to future minimum lease payments of $11.9 million under operating leases for office space, and to future vehicle minimum lease payments of $0.1 million through eleven months ending November 20, 2013.

At December 31, 2012 the Corporation is committed to $5.7 million in firm contracts relating to the transportation of natural gas.

At December 31, 2012 the Corporation has entered into contracts for drilling rig services under which the Corporation is committed to using services totaling $9.4 million during the eleven months ending November 30, 2013.

Subsequent to December 31, 2012, the Corporation surrendered a sublease for office space, reducing future minimum lease payments under operating leases by $2.0 million.

Litigation

The Corporation is involved in various claims and legal actions arising in the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

Financial Instruments

Refer to the "Commodity Pricing and Marketing" section.

Q4 2012 compared to Q3 2012

Refer to the "Quarterly Highlights" section.

Three months ended	**December 31, 2012**		**September 30, 2012**	
	1,969,260 BOE		1,001,880 BOE	
($000s)	$	$/BOE	$	$/BOE
Revenues	99,000	50.27	60,094	59.98
Realized gain on financial derivatives	7,320	3.72	1,362	1.36
Royalties	(16,413)	(8.34)	(6,897)	(6.88)
GCA[1]	3,892	1.98	1,015	1.00
Transportation costs	(4,474)	(2.27)	(2,048)	(2.04)
Operating costs	(23,195)	(11.78)	(18,238)	(18.20)
	66,130	**33.58**	**35,288**	**35.22**
G&A, excluding non-cash deferred compensation	(23,351)	(11.86)	(6,696)	(6.68)
Interest costs	(3,864)	(1.96)	(1,844)	(1.84)
Exploration expenses	(230)	(0.12)	-	-
Capital and other taxes	(278)	(0.14)	(202)	(0.20)
Funds flow from operations[2]	**38,407**	**19.50**	**26,546**	**26.50**

[1] *GCA means Gas Cost Allowance*
[2] *See "Non-GAAP Measurements"*

Funds flow from operations increased by $11.9 million or 45% during Q4 2012 compared to Q3 2012. Higher production volumes for all products, driven by the Guide Arrangement, which was completed on October 23, 2012, more than offset the incremental G&A costs associated with the transaction.

During the three months ended December 31, 2012, crude oil and NGL production averaged 11,995 Bbls/d, a 53% increase from 7,854 Bbls/d in Q3 2012. Natural gas production averaged 56.5 Mmcf/d in the fourth quarter of 2012, a 210% increase from 18.2 Mmcf/d in the third quarter of 2012. Total production per BOE increased 97% to 21,405 BOE/d from 10,890 BOE/d in Q3 2012.

Excluding transportation and financial derivative contracts, crude oil prices averaged $73.59/Bbl in Q4 2012, a 5% decrease from $77.06/Bbl realized in Q3 2012. Natural gas prices, before financial derivative contracts and transportation, averaged $3.35/Mcf in the fourth quarter of 2012, 37% higher than the $2.44/Mcf received in the third quarter of 2012.

The $7.3 million in realized gains on financial derivative contracts in Q4 2012 includes realized gains on natural gas derivative contracts obtained through the Guide Arrangement, in addition to oil hedges being unwound in October 2012 for proceeds of $2.4 million. The $4.4 million gain on natural gas derivative contracts during the quarter resulted in a $0.84/Mcf increase in the realized gas price, while the $2.9 million gain on oil derivative contracts resulted in a $2.95/Bbl increase in the realized price for crude oil.

Operating costs were $23.2 million during the fourth quarter of 2012 and $18.2 million during Q3 2012. On a per unit basis, operating costs were $11.78/BOE in the fourth quarter of 2012, a 35% decrease from $18.20/BOE during the three months ended September 30, 2012. The decrease reflects the lower cost Guide properties during the fourth quarter, as well as certain one-time non-recurring adjustments recorded in Q4 2012.

Net G&A expenses of $23.4 million in Q4 2012 were 249% higher than the expenses of $6.7 million in Q3 2012, reflecting the transaction and employee costs associated with the Guide Arrangement in October 2012.

During the fourth quarter of 2012, an impairment of $128.0 million was recorded, resulting primarily from a weakening of the future price forecasts, in addition to a reduction of the estimated reserve volumes at Kaybob.

Business Risks

General

Long Run is engaged in the exploration, development and production of crude oil and natural gas. The oil and gas business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory, environment and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of the capital markets, the Corporation's credit rating (if applicable) interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and the Corporation's securities in particular. Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Financial Risks

Financial risks include fluctuations in commodity prices, interest rates, the Canadian/US dollar exchange rate, and the cost of goods and services. The Corporation currently has financial contracts with Canadian banks (see "Commodity Pricing and Marketing" for details). The Corporation also manages these risks by maintaining a statement of financial position with prudent levels of debt measured by debt to funds flow from operations and debt coverage ratios. This allows for sufficient financial capacity to maintain exploration and development activity during a downturn in commodity prices.

Third Party Credit Risk

An additional risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Implementation of strategies for reducing greenhouse gases to meet the limits required could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition.

CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

IFRS 9 Financial Instruments

As of January 1, 2015, the Corporation will be required to adopt IFRS 9 – *Financial Instruments*, which is the result of the first phase of the IASB's project to replace IAS 39 – *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Corporation's financial statements will not be known until the project is complete.

IFRS 10 Consolidated Financial Statements

IFRS 10 *Consolidated Financial Statements* replaces the consolidation requirements in SIC-12 *Consolidation – Special Purpose Entities* and IAS 27 *Consolidated and Separate Financial Statements*. IFRS 10 provides a single consolidation model that applies to all entities, building on existing principles by identifying the concept of control as the determining factor in whether an entity should be consolidated within the financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where this is difficult to assess. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 11 Joint Arrangements

IFRS 11 *Joint Arrangements* establishes a principles-based approach to accounting for joint arrangements, focusing on the rights and obligations of the arrangement, rather than its legal form. Joint operations, whereby the jointly controlling parties have rights to the assets and obligations for the liabilities of the arrangement would be accounted for using proportionate consolidation. Joint ventures, whereby the jointly controlling parties have rights to the net assets of the arrangement would be accounted for using the equity method. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 12 Disclosure of Interests in Other Entities

The IASB has issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint ventures, and associates, as well as new disclosure requirements about unconsolidated structured entities. This standard is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 13 Fair Value Measurement

IFRS 13 establishes a single source of guidance for fair value measurements, when fair value is required or permitted by IFRS. The key features of IFRS 13 include a single framework for measuring fair value while requiring enhanced disclosures when fair value is applied, fair value would be defined as the 'exit price', and concepts of 'highest and best use' and 'valuation premise' would be relevant only for non-financial assets and liabilities. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IAS 27 Separate Financial Statements

As a result of the issue of the new suite of consolidation standards, IAS 27 *Separate Financial Statements* has been reissued, as the consolidation guidance will now be included in IFRS 10. IAS 27 will now only prescribe the accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares financial statements that are not consolidated. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IAS 28 Investments in Associates and Joint Ventures

As a consequence of the issue of IFRS 10, IFRS 11 and IFRS 12, IAS 28 has been amended. IAS 28 will provide the accounting guidance for investments in associates, and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

Critical Accounting Estimates

There are a number of critical estimates underlying the accounting policies employed in preparing the financial statements.

Oil and Gas Accounting

All expenditures incurred after the Corporation has obtained the legal right to explore associated with the exploration for and development of oil and gas properties are capitalized whether successful or not. Exploration and evaluation costs are capitalized and accumulated pending determination of technical feasibility and commercial viability. Exploration and evaluation assets are not depleted. For property and equipment, the aggregate of net capitalized costs and estimated future development costs less estimated residual values is amortized using the unit-of-production method based on estimated proved and probable oil and gas reserves.

Oil and gas accounting relies on the estimated proved and probable reserves believed to be recoverable from the oil and gas properties. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering/production and other relevant economic data. These estimates are subject to change as economic conditions change and ongoing production and development activities provide new information. The Corporation's reserves are evaluated annually by an independent firm and by the Corporation on a quarterly basis. Reserve estimates are critical to the following accounting estimates:

- Calculation of unit of production depletion. Proved and probable reserve estimates are used to determine the depletion and depreciation rate applied to each unit of production.
- Impairment of oil and gas assets. Estimated future cash flows are determined using the estimate of proved and probable reserves.

An increase in estimated proved and probable oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

The calculation of proved and probable reserves is affected by events, including the following:

- Changes to commodity prices
- Production performance of wells
- Changes to reservoir performance/pressures
- New geological and geophysical data
- Competitor production practices
- Changes to government regulations

As circumstances change and additional data becomes available, revisions are made to these estimates.

Property and equipment may be excluded from depletion until capable of operating in the manner intended by management and the estimated fair value of these assets is included in impairment calculations. Estimated residual values are also excluded from the depletion calculation.

Impairment Calculations

The Corporation is required to test the carrying value of exploration and evaluation assets for impairment if facts and circumstances suggest the carrying amount exceeds the recoverable amount, and when these assets are transferred to property and equipment. The Corporation is required to test property and equipment, including the carrying value of oil and gas assets, for impairment when indications of impairment exist. The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell. If either of these amounts exceeds the carrying value, the asset is considered not impaired. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. If this is the case, the recoverable amount is determined for the cash-generating unit (CGU) to which the asset belongs. The amount by which the carrying value exceeds the recoverable amount of an asset is charged to earnings. An impairment loss recognized in prior periods for an asset other than goodwill is reversed if there has been a change in facts and circumstances since the last impairment loss was recognized.

The recoverable amount of an oil and gas asset is based on estimates of fair value, reserves, production rates, petroleum and natural gas prices, future costs, recent market transactions, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Business Combinations

Business acquisitions are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of acquisition. In determining the fair value of the assets and liabilities, Long Run is often required to make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcome of any assumed contingencies. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the consideration transferred allocation and as a result, future net income.

Decommissioning Liabilities

The Corporation is required to provide for future abandonment and site restoration costs. The Corporation must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are capitalized to exploration and evaluation assets or property and equipment, as applicable. The costs capitalized to property and equipment are depleted into earnings based on units of production. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration, and review of potential abandonment methods.

Income Tax Accounting

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment subsequent to the financial statement reporting period. Accordingly, the actual income tax asset or liability may differ significantly from that estimated and recorded by management.

Controls and Procedures over Financial Reporting

Disclosure Controls and Procedures

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures are effective at the financial year end of the Corporation for the foregoing purposes.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Corporation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting at the financial year end of the Corporation and have concluded that the Corporation's internal controls over financial reporting are effective at the financial year end of the Corporation for the foregoing purposes.

The Corporation's CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the period commencing on October 1, 2012 and ended on December 31, 2012 that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No material changes in the Corporation's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's 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, can provide only reasonable, but not absolute, assurance that the objectives 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.

Share Information

The following table summarizes the outstanding shares of Long Run as of December 31:

	2012	2011
Common Shares	110,107,152	67,355,377
Non-Voting Convertible Shares	15,512,858	15,613,564
Options	8,042,000	4,849,135
Warrants to purchase 0.4167 Common Shares	2,300,000	-

At December 31, 2012, the closing price per Long Run common share was $4.90 per share. Applying this price to the Common Shares and Non-Voting Convertible Shares outstanding at December 31, 2012 generates a market value of approximately $615.5 million. As of March 7, 2013, the number of Common Shares and Non-Voting Convertible Shares outstanding were 110,107,152 and 15,512,858, respectively. As of March 7, 2013, the number of options and warrants outstanding were, 9,116,000 and 2,300,000, respectively.

Additional Information

Additional information relating to Long Run, including Long Run's Annual Information Form, can be accessed on-line on SEDAR at www.sedar.com, or from the Corporation's website at www.longrunexploration.com.

Quarterly Highlights[2]								
(unaudited)	**2012**	**2012**	**2012**	**2012**	**2011**	**2011**	**2011**	**2011**
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil (Bbl/d)	9,125	6,057	6,310	4,702	3,974	3,493	1,692	981
Heavy oil (Bbl/d)	1,538	1,128	868	518	530	542	461	591
Natural Gas (Mcf/d)	56,453	18,214	19,548	16,288	16,376	17,766	6,392	6,579
NGLs (Bbl/d)	1,332	669	1,113	913	1,368	1,464	90	104
BOE/d	**21,405**	**10,890**	**11,549**	**8,848**	**8,601**	**8,460**	**3,308**	**2,773**
Prices (*prior to financial derivatives and transportation charges*)								
Light oil ($/Bbl)	76.24	80.28	82.79	89.64	96.37	89.97	99.64	85.77
Heavy oil ($/Bbl)	57.89	59.77	64.03	71.13	77.17	64.01	72.08	59.08
Crude oil ($/Bbl)	73.59	77.06	80.52	87.80	94.02	86.46	93.74	75.74
Natural Gas ($/Mcf)	3.35	2.44	1.94	2.29	3.32	3.95	4.12	4.01
NGLs ($/Bbl)	67.08	62.24	74.95	84.60	83.90	85.11	74.94	63.48
Per BOE ($)								
Revenues	50.27	59.98	60.92	66.43	71.01	66.26	71.01	54.83
Realized gain (loss) on financial derivatives	3.72	1.36	0.65	(1.51)	(1.75)	0.53	(0.46)	1.02
Royalties, net of GCA	(6.36)	(5.88)	(5.52)	(6.06)	(7.49)	(10.21)	(5.24)	(5.57)
Transportation costs	(2.27)	(2.04)	(1.94)	(1.76)	(1.31)	(1.30)	(1.15)	(1.14)
Operating costs	(11.78)	(18.20)	(15.35)	(15.86)	(16.83)	(16.57)	(13.89)	(17.42)
Net	**33.58**	**35.22**	**38.76**	**41.24**	**43.63**	**38.71**	**50.27**	**31.72**
G&A, excluding non-cash compensation	(11.86)	(6.68)	(3.90)	(3.21)	(4.80)	(2.36)	(12.60)	(4.13)
Restructuring costs	-	-	-	-	-	-	-	-
Net interest expense	(1.96)	(1.84)	(2.06)	(1.41)	(0.92)	(1.00)	(2.12)	(0.60)
Exploration expenses	(0.12)	-	-	-	-	-	-	-
Capital and other taxes	(0.14)	(0.20)	(0.08)	(0.13)	(0.13)	(0.09)	(0.20)	(0.22)
Funds flow from operations [1]	**19.50**	**26.50**	**32.72**	**36.49**	**37.78**	**35.26**	**35.35**	**26.77**

[1] *See "Non-GAAP Measurements"*

[2] *Certain prior period amounts have been reclassified to conform to the current period presentation*

Quarterly Highlights[2]
(unaudited)

	2012	2012	2012	2012
	Q4	Q3	Q2	Q1
Financial ($000s)				
Petroleum and natural gas revenue, before royalties	99,000	60,094	64,025	53,486
Operating costs	23,195	18,238	16,128	12,767
General and administration expenses	21,899	7,154	4,482	3,199
Interest expense	3,864	1,844	2,161	1,136
Impairment of property and equipment	128,000	-	16,116	-
Funds flow from operations [1]	**38,407**	**26,546**	**34,385**	**29,381**
Per share, basic [1]	0.33	0.32	0.41	0.35
Per share, diluted [1]	0.33	0.32	0.41	0.35
Earnings (loss)	**(56,590)**	**(4,747)**	**17,506**	**1,179**
Per share, basic	(0.49)	(0.06)	0.21	0.01
Per share, diluted	(0.49)	(0.06)	0.21	0.01
Total assets	**1,193,272**	**725,914**	**731,657**	**711,876**
Weighted average outstanding shares – basic (000s)	115,421	82,969	82,969	82,969
Weighted average outstanding shares – diluted (000s)	115,421	83,016	83,061	83,121

[1] *See "Non-GAAP Measurements"*
[2] *Certain prior period amounts have been reclassified to conform to the current period presentation*

Quarterly Highlights[2]
(unaudited)

	2011	2011	2011	2011
	Q4	Q3	Q2	Q1
Financial ($000s)				
Petroleum and natural gas revenue, before royalties	56,192	51,568	21,377	13,685
Operating costs	13,314	12,898	4,181	4,348
General and administration expenses	3,851	1,834	3,795	1,030
Interest expense	725	781	638	151
Impairment of property and equipment	73,633	-	-	-
Funds flow from operations [1]	**29,896**	**27,448**	**10,641**	**6,681**
Per share, basic [1]	0.36	0.33	0.24	0.16
Per share, diluted [1]	0.36	0.33	0.23	0.16
Earnings (loss)	**(66,612)**	**11,427**	**4,387**	**(1,869)**
Per share, basic	(0.80)	0.14	0.10	(0.05)
Per share, diluted	(0.80)	0.14	0.10	(0.05)
Total assets	**665,811**	**677,711**	**627,778**	**278,018**
Weighted average outstanding shares – basic (000s)	82,969	82,969	44,822	41,130
Weighted average outstanding shares – diluted (000s)	83,066	83,315	45,388	41,130

[1] *See "Non-GAAP Measurements"*
[2] *Certain prior period amounts have been reclassified to conform to the current period presentation*

Significant factors and trends that have impacted the Corporation's results during the above periods include:

Production averaged 13,189 BOE/d during 2012, an increase of 127% from the average 2011 production of 5,809 BOE/d. In addition to volumes from new wells drilled, the production increase during the year ended December 31, 2012 includes the impact of the Viking asset acquisition on December 9, 2011 and the Guide Arrangement, which was completed on October 23, 2012.

Volatility in commodity prices has persisted in 2012. Oil prices experienced volatility due to North American pipelines constraints. This has led to a further discount between Canadian and US benchmark oil prices. Gas price volatility was due to high supply levels in North America that tested storage capacity levels.

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility and improving netback cash flows, Long Run has entered into several natural gas and crude oil financial contracts. During 2012, Long Run recorded realized gains of $8.1 million on financial contracts, compared to a loss of $0.9 million in 2011. Oil hedges were unwound in October 2012 for proceeds of $2.4 million, and spot prices for both oil and natural gas in 2012 were lower than the prices Long Run had secured using financial contracts.

Gross general and administration expenses increased $29.7 million in 2012 compared to 2011. The increase reflects the $20.2 million of transaction and employee costs related to the Guide Arrangement.

At December 31, 2012 the Corporation recorded an impairment expense of $144.1 million related to property and equipment (December 31, 2011 - $73.6 million). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the discounted value of the after-tax cash flows from oil and gas reserves, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally.

LONG RUN EXPLORATION LTD.
Statements of Financial Position

($000s)	December 31, 2012	December 31, 2011
ASSETS		
CURRENT		
Cash (note 11)	3,803	7,581
Accounts receivable (note 17)	48,912	27,458
Deposits and prepaid expenses	7,156	2,378
Fair value of financial derivatives (note 17)	15,318	-
	75,189	37,417
Exploration and evaluation assets (note 7)	20,936	-
Property and equipment (notes 5, 6, 8 and 10)	939,713	585,826
Deferred income tax asset (note 14)	157,292	40,582
Fair value of financial derivatives (note 17)	142	-
Goodwill (note 9)	-	1,986
	1,193,272	**665,811**
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	91,821	38,170
Bank loan (note 11)	261,173	-
Fair value of financial derivatives (note 17)	9,341	5,607
	362,335	43,777
Bank loan (note 11)	-	124,000
Decommissioning liabilities (note 10)	233,100	42,171
Fair value of financial derivatives (note 17)	12,155	305
Deferred compensation on farm-out agreement (note 8)	-	5,000
Deferred compensation (note 12)	-	64
	607,590	215,317
SHAREHOLDERS' EQUITY		
Share capital (note 12)	657,455	485,727
Contributed surplus (note 12)	16,558	10,446
Retained earnings (deficit)	(88,331)	(45,679)
	585,682	450,494
	1,193,272	**665,811**

Commitments and contingencies (note 16)

See accompanying notes

Approved on behalf of the Board

"Signed"
Patricia Newson
Director

"Signed"
Brad Munro
Director

LONG RUN EXPLORATION LTD.
Statements of Earnings (Loss) and Comprehensive Income (Loss)

($000s, except share and per share amounts)	Year ended December 31 2012	2011
INCOME		
Petroleum and natural gas revenue	276,605	142,822
Royalties, net of gas cost allowance	(29,096)	(16,841)
Realized gain (loss) on financial derivatives (note 17)	8,149	(852)
Unrealized gain (loss) on financial derivatives (note 17)	7,451	(3,902)
Gain (loss) on disposal of assets (note 8)	75,776	(183)
Gain on farm-outs (note 8)	11,373	-
	350,258	121,044
EXPENSES		
Operating	70,328	34,741
Transportation	9,975	2,680
General and administration (note 13)	36,734	10,510
Share-based compensation (note 12)	5,530	3,741
Interest (note 11)	9,005	2,295
Exploration expenses	230	-
Accretion (note 10)	2,019	884
Derecognition expenses	784	-
Depletion and depreciation	121,568	54,294
Impairment of property and equipment (note 6)	144,116	73,633
Impairment of goodwill (note 9)	1,986	-
	402,275	182,778
Loss before taxes	(52,017)	(61,734)
Income taxes (note 14)		
Capital and other taxes	667	287
Deferred income tax recovery	(10,032)	(9,354)
	(9,365)	(9,067)
NET LOSS AND COMPREHENSIVE LOSS	**(42,652)**	**(52,667)**
NET LOSS AND COMPREHENSIVE LOSS PER SHARE (note 12)		
Basic	(0.47)	(0.83)
Diluted	(0.47)	(0.83)
Weighted average shares outstanding - basic	91,126,249	63,141,989
- diluted	91,126,249	63,555,607

See accompanying notes

LONG RUN EXPLORATION LTD.
Statement of Changes in Equity

($000s)	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total
	(note 12)	*(note 12)*		
Balance, January 1, 2011	182,541	5,736	6,988	195,265
Shares issued for cash	44,001	-	-	44,001
Shares issued upon business acquisition (note 5)	261,270	-	-	261,270
Share-based compensation	-	4,813	-	4,813
Options exercised	301	(103)	-	198
Share issue costs	(2,386)	-	-	(2,386)
Comprehensive loss	-	-	(52,667)	(52,667)
Balance, December 31, 2011	485,727	10,446	(45,679)	450,494
Shares issued upon the Guide Arrangement (note 5)	171,130	-	-	171,130
Share-based compensation	-	6,433	-	6,433
Options exercised	598	(321)	-	277
Comprehensive loss	-	-	(42,652)	(42,652)
Balance, December 31, 2012	657,455	16,558	(88,331)	585,682

See accompanying notes

LONG RUN EXPLORATION LTD.
Statements of Cash Flows

($000s)	Year ended December 31 2012	2011
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net loss	(42,652)	(52,667)
Items not requiring cash:		
Deferred income tax recovery	(10,032)	(9,354)
Impairment of goodwill	1,986	-
Impairment of property and equipment	144,116	73,633
Depletion and depreciation	121,568	54,294
Derecognition expenses	784	-
Accretion	2,019	884
Share-based compensation	5,530	3,741
Gain on farm-outs	(11,373)	-
Loss (gain) on disposal of assets	(75,776)	183
Unrealized loss (gain) on financial derivatives	(7,451)	3,902
Deferred compensation (note 12)	-	50
Abandonment costs (note 10)	(804)	(446)
Change in non-cash working capital (note 19)	8,121	(422)
	136,036	73,798
FINANCING ACTIVITIES		
Issue of common shares, net of costs (note 12)	277	40,961
Bank loan (repayment)	(103,859)	63,113
	(103,582)	104,074
INVESTING ACTIVITIES		
Exploration and evaluation expenditures (note 7)	(4,715)	-
Additions to property and equipment (note 5, 8)	(205,695)	(179,995)
Corporate acquisitions (note 5)	-	3,679
Disposals of oil and gas properties (note 8)	178,241	1,817
Deferred compensation on farm-out agreement (note 8)	-	5,000
Change in non-cash working capital (note 19)	(4,063)	(792)
	(36,232)	(170,291)
CHANGE IN CASH	(3,778)	7,581
CASH, BEGINNING OF PERIOD	7,581	-
CASH, BEGINNING AND END OF PERIOD	3,803	7,581

SUPPLEMENTAL INFORMATION

	2012	2011
Cash interest paid	8,502	2,505
Cash taxes paid	725	287

See accompanying notes

Unless otherwise stated, amounts presented in these notes are in dollars and tabular amounts are in thousands of Canadian dollars, except number of shares and per share amounts.

1. REPORTING ENTITY

Long Run Exploration Ltd. ("Long Run" or the "Corporation"), formerly WestFire Energy Ltd. ("WestFire"), is incorporated under the *Business Corporations Act* (Alberta). The business of the Corporation is the acquisition of, exploration for and development of petroleum and natural gas properties in western Canada. Long Run's outstanding common shares are listed on the Toronto Stock Exchange under the symbol "LRE".

The principal address of the Corporation is located at 400, 250 Second Street SW, Calgary, Alberta, T2P 0C1.

2. BASIS OF PREPARATION

Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS") and were authorized for issue by the Board of Directors on March 7, 2013.

Basis of presentation

The financial statements have been prepared on the historical cost basis except for derivative financial instruments which are measured at fair value, as explained in note 17.

Estimates, assumptions and judgements

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The amounts recorded for exploration and evaluation assets, property and equipment, depletion and depreciation and impairment testing are based on estimates of proven and probable reserves, production rates, oil and natural gas prices, future costs, future prices, and other relevant assumptions. As well, the cash generating unit to which an asset belongs is subject to the judgement of management.

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves. Future price estimates are used in impairment testing. Changes in the economic environment could result in significant changes to the discount rate used to calculate net present values.

Business acquisitions are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of acquisition. In determining the fair value of the assets and liabilities, Long Run is often required to make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcome of any assumed contingencies. Changes in any of these assumptions would impact amounts assigned to assets and liabilities and goodwill in the consideration transferred allocation and as a result, future net income.

The provision for decommissioning liabilities is based on estimates of costs and expected plans for remediation. Actual costs may differ from those estimated due to changes in laws and regulations, technology, market and other conditions.

Accruals for royalties and costs are prepared based on estimates when actual amounts are not yet known. Share-based compensation amounts are determined using certain assumptions (see note 12). The fair value of financial derivatives is based on fair values provided by the counterparties with whom the transactions were completed (see note 17). By their nature, these estimates and assumptions are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

The provision for income and other tax liabilities, requiring the interpretation of complex laws and regulations which are subject to change, is subject to measurement uncertainty. The recognition of income tax assets requires a determination of the likelihood that they will realized from future taxable earnings.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and cash equivalents

Cash and cash equivalents may include highly liquid short-term investments with initial maturities of three months or less. They are recorded at cost which approximates fair market value.

Financial instruments

The financial instruments recognized on the Corporation's statement of financial position are deemed to approximate their estimated fair values. All financial assets except derivatives are classified as loans or receivables and are accounted for on an amortized cost basis. All financial liabilities except derivatives are classified as other liabilities.

Derivative instruments have not been designated as accounting hedges and are recorded on the statement of financial position at fair value with actual amounts received or paid on the settlement of the derivative financial instrument recorded in income.

Joint interests

The Corporation's petroleum and natural gas activities may be conducted jointly with others. A jointly controlled operation involves the joint use of assets contributed to the joint venture, without the establishment of a corporation, partnership, or other entity. The financial statements reflect only the Corporation's proportionate interest in such activities.

Exploration and evaluation assets

Expenditures incurred before the Corporation has obtained the legal right to explore are expensed in the statement of earnings.

Exploration and evaluation costs reflect expenditures for an area where technical feasibility and commercial viability had not yet been determined. Expenditures, including land acquisition, geological and geophysical, drilling and completion costs are capitalized and accumulated pending determination of technical feasibility and commercial viability. Evaluation and exploration expenditures are not depleted. When assets are determined to be technically feasible and commercially viable, the accumulated costs are tested for impairment and transferred to property and equipment. Technical feasibility and commercial viability is considered established when there are considered to be commercial quantities of reserves in existence.

Exploration and evaluation assets are also assessed for impairment if facts and circumstances suggest the carrying amount exceeds the recoverable amount.

Property and equipment

Property and equipment are stated at cost less accumulated depletion and depreciation, and accumulated impairment losses.

Petroleum and natural gas properties

Property and equipment includes transfers of exploration and evaluation assets, property acquisitions, facilities, directly attributable overhead and share-based compensation expenses, as well as land acquisition, geological and geophysical, drilling and completion costs incurred within an area considered to be technically feasible and commercially viable.

Property and equipment is depleted on the unit-of-production method using estimated gross proven and probable petroleum and natural gas reserves, determined annually by independent professional engineers. Petroleum and natural gas reserves are converted to a common unit of measure on an energy equivalent basis of six mcf of gas to one barrel of oil. Assets may be excluded from depletion until capable of operating in the manner intended by management. Estimated future development costs necessary to bring the reserves into production are included in the depletion calculation. Estimated residual values are excluded from the depletion calculation.

Reserves are the remaining quantities of oil, natural gas and related substances from known accumulations estimated to be recoverable from a given date forward. The estimates of reserves are determined from drilling, geological, geophysical and engineering data based on established technology and specified economic conditions. The guidelines for the determination and classification of reserves are outlined in the Canadian Oil and Gas Evaluation Handbook.

Proven plus probable reserve estimate is defined as a "best estimate" of the remaining recoverable quantities of oil, natural gas and related substances. This estimate should best represent the expected outcome with no optimism or conservatism. In probabilistic terms, there should be at least a 50 percent probability that the quantities actually recovered in the future will equal or exceed the proven plus probable reserve estimate.

Proven plus probable reserves can be divided into developed and undeveloped reserves. Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities. Developed reserves will typically require little or no future development capital to be realized and can be further subdivided into producing and non-producing. Undeveloped reserves are those reserves from known accumulations where a significant expenditure (e.g., drilling a well) is required to render them capable of production.

Property and equipment is tested for impairment when indications of impairment exist.
Drilling credits earned under government incentive programs are recorded as a reduction of petroleum and natural gas properties.

Office furniture and equipment

Office furniture, equipment and other assets are recorded at cost and depreciated on a declining balance basis at rates ranging from 10% - 30% per year.

Disposals

Any gain or loss on the disposal of assets, including oil and natural gas properties, determined as the difference between the net disposal proceeds and the carrying amount of the asset, is recognized in the statement of earnings.

Non-monetary transactions

Non-monetary transactions for the acquisition or disposal of property and equipment are measured at fair value, unless the transaction lacks commercial substance or fair value cannot be reliably measured.

Derecognition

The carrying amount of an asset is derecognized on disposal or when future economic benefits are no longer expected from its use or disposal, with the resulting gain or loss recognized in the statement of earnings.

Goodwill

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of net assets acquired. When the excess is negative, it is recognized immediately in the statement of earnings.

Goodwill, measured at cost less accumulated impairment losses, is tested for impairment annually. For purposes of impairment testing, goodwill acquired in a business combination is allocated to the cash-generating units that are expected to benefit from the synergies of the combination and tested for impairment at the operating segment level. An impairment loss in respect of goodwill is not reversed.

Business combinations

Transactions for the purchase of assets, where the assets acquired are deemed to constitute a business, are accounted for as business combinations. Using the acquisition method, identifiable assets acquired and liabilities assumed are measured at their acquisition-date fair values. Transaction costs related to the acquisition are expensed in the statement of earnings.

Impairments

The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell. If either of these amounts exceeds the carrying value, the asset is considered not impaired. The recoverable amount is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. If this is the case, the recoverable amount is determined for the cash-generating unit (CGU) to which the asset belongs.

In assessing value in use, 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 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 proven and probable reserves.

Fair value less costs to sell is the amount obtainable from the sale of an asset in an arm's length transaction between knowledgeable and willing parties, less the costs of disposal. In determining fair value less costs to sell, available fair value indicators, such as recent market transaction information, and an appropriately discounted cash flow valuation model are used.

Impairment losses are recognized in the statement of earnings. An impairment loss recognized in respect of a CGU is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and subsequently to other assets in the CGU. An impairment loss recognized in prior periods for an asset other than goodwill is reversed if there has been a change in facts and circumstances used to determine the asset's recoverable amount since the last impairment loss was recognized, such that the impairment loss no longer exists or has decreased. An impairment loss is only reversed to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

Leases

The Corporation's leases are classified as either financing or operating. Financing leases are those which transfer substantially all the benefits and risks of ownership to the lessee. Assets acquired under financing leases are depleted along with property and equipment. Obligations recorded under financing leases are reduced by the principal portion of lease payments as incurred and the imputed interest portion of financing lease payments is charged to interest expense. Payments under operating leases are expensed as incurred.

Decommissioning liabilities

Decommissioning liabilities arise from the legal obligation to abandon and reclaim property, plant and equipment incurred upon acquisition, construction, development and/or normal use of the asset. The initial liability is measured at the discounted value of the estimated costs to reclaim and abandon using a risk free rate, subsequently adjusted for the accretion of discount and changes in expected costs. The decommissioning cost is capitalized as part of exploration and evaluation assets or property and equipment, as applicable. The costs capitalized to property and equipment are depleted into earnings based on units of production. Actual costs incurred upon settlement of the obligations are charged against the liability.

Revenue recognition

Petroleum and natural gas sales are recognized when delivery of the product has been completed and title passes to an external party.

Share-based compensation

The grant date fair values of share-based compensation awards are recognized over the vesting periods of the awards, with an offsetting credit to contributed surplus. The Black-Scholes option pricing model has been used to calculate the fair value of the stock options granted. The estimated forfeiture rate is adjusted to reflect the actual number of options that vest. Consideration paid by optionees on the exercise of stock options is credited to share capital, together with the related share-based compensation previously included in contributed surplus.

Cash settled compensation plans

From time to time the company may choose to award employees and directors with performance based incentives derived from the performance of the Corporation's share price. Such plans are settled in cash, measured at fair value at the end of each reporting period, and are recorded as a liability on the statement of financial position, with changes in fair value included in the statement of earnings.

Income taxes

Income tax expense is recognized in the statement of earnings, except to the extent it relates to items recognized directly in equity, in which case the related income tax is also recognized in equity.

Deferred tax is recognized using the statement of financial position method. Under this method, deferred income tax assets and liabilities are recognized based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period in which the change is substantively enacted. Deferred income tax assets and liabilities are presented as non-current.

Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is neither a business combination nor an event resulting in income or expense. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. A deferred tax asset is recognized only to the extent it is probable that future taxable profits will be available against which the asset can be utilized.

Flow-through shares

The Corporation may finance a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits to the Corporation, a deferred tax expense is recognized in the statement of earnings when the expenditures are incurred and the renouncement has been filed. The deferred tax expense recognized is offset by the premium received for the flow-through shares, with the premium being initially recorded as a liability in the statement of financial position.

Earnings (loss) per share

Basic earnings (loss) per share amounts are calculated by dividing the net earnings or loss by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share amounts are calculated using the treasury stock method, whereby diluted earnings per share is determined by adjusting the earnings or loss and the weighted average number of common shares outstanding for the effects of dilutive instruments such as outstanding stock options.

Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation.

4. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

IFRS 9 Financial Instruments

As of January 1, 2015, the Corporation will be required to adopt IFRS 9 – *Financial Instruments*, which is the result of the first phase of the IASB's project to replace IAS 39 – *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Portions of the standard remain in development and the full impact of the standard on the Corporation's financial statements will not be known until the project is complete.

IFRS 10 Consolidated Financial Statements

IFRS 10 *Consolidated Financial Statements* replaces the consolidation requirements in SIC-12 *Consolidation – Special Purpose Entities* and IAS 27 *Consolidated and Separate Financial Statements*. IFRS 10 provides a single consolidation model that applies to all entities, building on existing principles by identifying the concept of control as the determining factor in whether an entity should be consolidated within the financial statements of the parent company. The standard provides additional guidance to assist in the determination of control where this is difficult to assess. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 11 Joint Arrangements

IFRS 11 *Joint Arrangements* establishes a principles-based approach to accounting for joint arrangements, focusing on the rights and obligations of the arrangement, rather than its legal form. Joint operations, whereby the jointly controlling parties have rights to the assets and obligations for the liabilities of the arrangement would be accounted for using proportionate consolidation. Joint ventures, whereby the jointly controlling parties have rights to the net assets of the arrangement would be accounted for using the equity method. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 12 Disclosure of Interests in Other Entities

The IASB has issued IFRS 12 *Disclosure of Interests in Other Entities*, which contains enhanced disclosure requirements about an entity's interests in subsidiaries, joint ventures, and associates, as well as new disclosure requirements about unconsolidated structured entities. This standard is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IFRS 13 Fair Value Measurement

IFRS 13 establishes a single source of guidance for fair value measurements, when fair value is required or permitted by IFRS. The key features of IFRS 13 include a single framework for measuring fair value while requiring enhanced disclosures when fair value is applied, fair value would be defined as the 'exit price', and concepts of 'highest and best use' and 'valuation premise' would be relevant only for non-financial assets and liabilities. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IAS 27 Separate Financial Statements

As a result of the issue of the new suite of consolidation standards, IAS 27 *Separate Financial Statements* has been reissued, as the consolidation guidance will now be included in IFRS 10. IAS 27 will now only prescribe the accounting and disclosure requirements for investments in subsidiaries, joint ventures and associates when an entity prepares financial statements that are not consolidated. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

IAS 28 Investments in Associates and Joint Ventures

As a consequence of the issue of IFRS 10, IFRS 11 and IFRS 12, IAS 28 has been amended. IAS 28 will provide the accounting guidance for investments in associates, and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The adoption of this standard is not expected to have a material impact on the Corporation's financial statements.

5. BUSINESS COMBINATIONS

Arrangement with Guide Exploration Ltd.

On October 23, 2012, the Corporation completed a plan of arrangement (the "Guide Arrangement") with Guide Exploration Ltd. ("Guide"). Details of the transaction are as follows:

	$
Exploration and evaluation assets	16,221
Property and equipment	406,299
Deferred tax asset	107,110
Working capital deficiency	(23,361)
Financial derivatives	(7,575)
Bank loan	(241,032)
Decommissioning liabilities	(86,100)
Other liability	(432)
Identifiable net assets	171,130
Consideration given:	
Common shares (42,569,632 Common Shares at $4.02 per share)	171,130

Following completion of the Guide Arrangement, property and equipment and the decommissioning liabilities were increased by $83.3 million, reflecting the calculation of decommissioning liabilities using a risk free discount rate, compared to a credit adjusted discount rate, in accordance with the Corporation's accounting policy.

The purchase price allocation was based on the best estimates of management, giving consideration to cash flows from oil and gas reserves estimated by independent reserve evaluators, and the fair value of undeveloped land estimated internally.

Transaction costs, including salary and employee expenses, of $20.2 million related to the Guide Arrangement are included in the statement of earnings as a general and administrative expense.

The financial statements incorporate the operations of the Guide properties commencing October 23, 2012. During the period October 23, 2012 to December 31, 2012, the properties acquired contributed revenues of $40.0 million and net earnings of $3.0 million.

Had the business combination with Guide closed on January 1, 2012, management estimates that the corporate activity of Guide, adjusted for the property and equipment, deferred tax and decommissioning obligation values determined on the date of completion of the Guide Arrangement, would have increased revenues and the net loss by a $148.0 million and $2.0 million, respectively.

Acquisition of oil and natural gas properties

On December 9, 2011, the Corporation purchased interests in certain Viking assets in the Redwater area of Alberta. Details of the transaction are as follows:

	$
Property and equipment	44,942
Decommissioning liabilities	(4,617)
Fair value of net assets	40,325
Cash consideration paid	40,325

The financial statements incorporate the operations of the acquired properties commencing December 9, 2011. During the period December 9, 2011 to December 31, 2011, the Corporation recorded revenues of $0.7 million and net earnings of $0.1 million in respect of these assets.

Had the transaction closed on January 1, 2011, management estimates that revenue and net earnings would have increased by an additional $11.0 million and $2.0 million, respectively. In determining these amounts, management assumed the fair values on the date of acquisition would have been the same if the acquisition had occurred on January 1, 2011.

Acquisition of Orion Oil & Gas Corporation

On June 30, 2011, the Corporation acquired all of the issued and outstanding shares of Orion Oil & Gas Corporation ("Orion"). Details of the transaction are as follows:

	$
Cash	3,679
Accounts receivable and prepaid expenses	21,830
Property and equipment	344,575
Accounts payable	(19,173)
Financial derivatives	(1,730)
Bank loan	(52,797)
Deferred tax liability	(27,298)
Decommissioning liabilities	(7,816)
Fair value of net assets	261,270
Consideration given:	
Common Shares and Convertible Non-Voting Shares (38,141,627 shares at $6.85 per share)	261,270

The purchase price allocation was based on the best estimates of management, based principally on valuations prepared by independent valuation specialists.

The financial statements incorporate the operations of the Orion properties commencing June 30, 2011. During the period June 30, 2011 to December 31, 2011, the acquisition contributed revenues of $54.0 million and net earnings of $9.0 million.

Had the transaction closed on January 1, 2011, management estimates that revenue would have increased by $57.0 million and net earnings would have increased by $8.0 million during the year ended December 31, 2011. In determining these amounts, management assumed the fair values on the date of acquisition would have been the same if the acquisition had occurred on January 1, 2011.

6. IMPAIRMENT OF PROPERTY AND EQUIPMENT

For the year ended December 31, 2012, the Corporation recorded an impairment expense of $144.1 million related to property and equipment (December 31, 2011 - $73.6 million). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the net present value of the after-tax cash flows from oil and gas reserves, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land.

During the year ended December 31, 2012, impairments were recorded at the Kaybob and Redwater CGU's, resulting primarily from a weakening of the future price forecasts and a reduction of the estimated reserve volumes at Kaybob.

The net present values of the cash flows from oil and gas reserves at December 31, 2012 were calculated using an after-tax discount rate of 10%, a CDN$/US$ exchange rate of 1.0 CDN$ to 1.0 US$, and the following forward commodity price estimates:

Year	WTI Oil (US$/bbl)	AECO Gas (CDN$/mcf)
2013	90.71	3.35
2014	91.64	3.80
2015	92.30	4.18
2016	96.17	4.71
2017	97.29	5.12
2018	98.44	5.36
2019	99.94	5.45
2020	101.76	5.57
2021	103.61	5.67
2022	105.54	5.77
2023	107.46	5.87
Remainder	+2.0%/yr	+2.0%/yr

A one percent increase in the assumed after tax discount rate would result in an additional impairment of approximately $13.0 million as at December 31, 2012, while a 10% decrease in the forward commodity price estimates would result in an additional impairment of approximately $74.0 million.

At December 31, 2011 an impairment charge of $73.6 million was recorded, with approximately ninety percent of the impairment loss attributable to the natural gas weighted Kaybob CGU, and the balance attributed to the Alberta heavy oil CGU.

7. EXPLORATION AND EVALUATION ASSETS

	$
Balance, January 1, 2011 and December 31, 2011	-
Guide Arrangement (note 5)	16,221
Additions	4,715
Balance, December 31, 2012	20,936

8. PROPERTY AND EQUIPMENT

Cost	$
Balance, January 1, 2011	209,502
Additions	152,958
Acquisitions (note 5)	389,517
Disposals	(2,460)
Balance, December 31, 2011	749,517
Additions	241,299
Guide Arrangement (note 5)	489,581
Disposals	(134,457)
Derecognition expense	(784)
Balance, December 31 , 2012	1,345,156

Accumulated depletion, depreciation and impairments	$
Balance, January 1, 2011	35,764
Depletion and depreciation expense	54,294
Impairment (note 6)	73,633
Balance, December 31, 2011	163,691
Depletion and depreciation expense	121,568
Disposals	(23,932)
Impairment (note 6)	144,116
Balance, December 31, 2012	405,443

Net book value	$
Balance, December 31, 2011	585,826
Balance, December 31, 2012	939,713

As at December 31, 2012, $31.4 million (December 31, 2011 - $Nil) of undeveloped land has been excluded from, and $562.4 million (December 31, 2011 - $476.7 million) in future development costs have been added into, the cost bases for depletion purposes. Estimated residual values of $50.1 million have been excluded from costs subject to depletion (December 31, 2011 - $10.8 million).

For the year ended December 31, 2012, $2.8 million (December 31, 2011 – $1.2 million) of salaries and wages have been capitalized relating to geological and geophysical activities.

During 2011, the Corporation entered into a farm-out agreement with an industry partner (the "Farmee") on lands in the west central area of Saskatchewan, whereby the Farmee had committed to drill, complete and equip or abandon thirty horizontal wells on or before December 31, 2012. The Farmee was obligated to pay seventy-five percent of the costs of the wells to earn a fifty percent working interest in the farm-out lands. The agreement further stipulated that the Farmee must drill, complete, and equip or abandon fifteen of the commitment wells on or before December 31, 2011 in order to retain the lands under this agreement. The Farmee had satisfied the 2011 commitment by December 31, 2011. The Corporation received $5.0 million as initial consideration under this agreement, which was recorded as deferred compensation on the statement of financial position as of December 31, 2011.

Upon completion of the farm-out commitment during 2012, the Corporation recognized a gain of $11.4 million, representing 33% of the accumulated costs of the Farmee during the earning period and the $5.0 million of initial consideration received, less fifty percent of the original cost of the farm-out lands prior to the farm-out arrangement .

During the year ended December 31, 2012, the Corporation disposed of properties, including the farm-out properties in west central Saskatchewan, for gross proceeds of $178.2 million, resulting in a net gain on disposal of assets of $75.8 million.

9. GOODWILL

	2012	**2011**
	$	$
Balance, beginning of the period	1,986	1,986
Impairment	(1,986)	-
Balance, end of the period	-	1,986

The Corporation reviewed the valuation of goodwill as of December 31, 2012 and determined that the recoverable amount had declined below the carrying value. Based upon this review, an impairment of goodwill of $2.0 million was recorded as a non-cash charge to earnings as of December 31, 2012 (December 31, 2011 - $Nil).

10. DECOMMISSIONING LIABILITIES

The Corporation's decommissioning liabilities result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its decommissioning liabilities is approximately $349.0 million, which will be incurred over the next 40 years. A risk free rate of 2.5% and an inflation rate of 2% were used to calculate the present value of the decommissioning liabilities as at December 31, 2012 (December 31, 2011 – 2.5% and 2%, respectively). At December 31, 2012, the Corporation revised the estimated costs related to decommissioning liabilities.

	2012	2011
Year ended December 31	$	$
Balance, beginning of period	42,171	17,098
Accretion expense	2,019	884
Liabilities acquired	169,382	12,433
Liabilities incurred	7,814	2,421
Disposal of liabilities	(8,060)	(307)
Settlement of liabilities	(804)	(446)
Change in estimates	20,578	10,088
Balance, end of period	233,100	42,171

11. AVAILABLE CREDIT FACILITIES

The Corporation has credit facilities of $450.0 million, consisting of a $420.0 million revolving syndicated facility and a $30.0 million operating facility. The credit facilities terminate on May 31, 2015 unless extended. Total borrowings permitted under these facilities cannot exceed the borrowing base, which is determined by the lenders, and occurs semi-annually or upon the occurrence of a material adverse effect. The borrowing base established by the syndicate as at December 31, 2012 is $430.0 million.

Security for the credit facilities includes a demand debenture for $1.0 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Corporation. At December 31, 2012, an amount of $261.2 million was drawn against the credit facilities (December 31, 2011 - $124.0 million).

The credit facilities bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances requires the payment of a stamping fee equal to a margin. The margins range from 1.00% per annum to 4.00% per annum, based upon the Corporation's debt to EBITDA ratio. For the year ended December 31, 2012, the effective interest rate, including standby and other fees, was 4.6% (December 31, 2011 – 5.5%).

An annual review of the credit facilities is scheduled to occur on or before May 31, 2013. As at December 31, 2012, the Corporation is in compliance with all covenants, obligations and conditions of its credit agreement, which include covenants relating to debt to EBITDA, permitted dispositions, and permitted hedging.

As at December 31, 2012, the Corporation had cash on deposit as security for outstanding letters of credit totalling $3.8 million. Subsequent to December 31, 2012, the letters of credit were returned and the monies refunded.

12. SHARE CAPITAL

Authorized

Unlimited number of Common Shares

Unlimited number of Common Non-Voting Shares

Unlimited number of Non-Voting Convertible Shares

The holders of the Non-Voting Convertible Shares are entitled to receive dividends declared thereon equally, on a share-for-share basis, with the holders of Common Shares. The holders of Non-Voting Convertible Shares are entitled to attend meetings of shareholders, but are not entitled to vote. In the event of liquidation, dissolution or winding up of the affairs of the Corporation, the holders of the Non-Voting Convertible Shares are entitled to receive an amount per share equal to the fair market value of any property received as consideration by the Corporation for the issuance of the shares, before any amount is distributed to holders of the Common Shares. The Non-Voting Convertible Shares may not be transferred to a control person, meaning a person or company holding more than 20% of the voting securities of the Corporation. Holders of Non-Voting Convertible Shares may convert each share into one Common Share, provided the holder would not become a control person of the Corporation after the conversion, or upon a change in control of the Corporation, and are automatically converted on a transfer of the share to a person that would not be a control person of the Corporation after giving effect to such transfer. The Corporation has the right to require holders of the Non-Voting Convertible Shares to convert all issued and outstanding shares to Common Shares three years after the date the Non-Voting Convertible Shares were issued.

Unlimited number of First Preferred Shares, issuable in series

Issued

Common Shares	Number of Shares	Amount $
Balance, January 1, 2011	**39,935,315**	**182,541**
Issued for cash (a)	4,862,000	44,001
Issued for shares of Orion (b)	22,527,938	154,316
Issued on exercise of stock options	29,999	198
Issued on conversion of Non-Voting Convertible Shares	125	1
Transfer from contributed surplus on exercise of options	-	103
Share issue costs, net of deferred tax of $852	-	(2,386)
Balance, December 31, 2011	**67,355,377**	**378,774**
Issued for shares of Guide (c)	42,569,632	171,130
Issued on conversion of Non-Voting Convertible Shares	100,706	690
Issued on exercise of stock options (d)	81,437	277
Transfer from contributed surplus on exercise of options	-	321
Balance, December 31, 2012	**110,107,152**	**551,192**

Non-Voting Convertible Shares	Number of Shares	Amount $
Balance, January 1, 2011	-	-
Issued for shares of Orion (b), (e)	15,613,689	106,954
Cancelled on conversion to Common Shares	(125)	(1)
Balance, December 31, 2011	**15,613,564**	**106,953**
Cancelled on conversion Common Shares	(100,706)	(690)
Balance, December 31, 2012	**15,512,858**	**106,263**

Total Common Shares and Non-Voting Convertible Shares	Number of Shares	Amount $
Balance, December 31, 2011	**82,968,941**	**485,727**
Balance, December 31, 2012	**125,620,010**	**657,455**

Warrants	Number of Warrants	Weighted Average Exercise Price $
Balance, January 1, 2011 and December 31, 2011	-	-
Issued upon Guide Arrangement (f)	2,300,000	7.44
Balance, December 31, 2012	**2,300,000**	**7.44**

a) On March 9, 2011, the Corporation issued 4,862,000 Common Shares for gross proceeds of $44.0 million under a bought deal basis at a price of $9.05 per Common Share.

b) On June 30, 2011 the Corporation acquired all of the outstanding shares of Orion Oil & Gas Corporation in consideration for the issuance of 22,527,938 Common Shares and 15,613,689 Non-Voting Convertible Shares (note 5).

c) On October 23, 2012 the Corporation issued 42,569,632 Common Shares pursuant to the Guide Arrangement in consideration for all of the outstanding shares of Guide (note 5).

d) The 177,600 options exercised, including cashless exercises, resulting in the issuance of 81,437 common shares.

e) The Corporation can require the holders of the Non-Voting Convertible Shares to convert to Common Shares after June 30, 2014.

f) Each warrant entitles the holder to acquire 0.4167 Common Share of the Corporation at an exercise price of $3.10 per 0.4167 of a share until September 15, 2014. The Warrants are not exercisable until the twenty day volume weighted average trading price of the Common Shares exceeds $12.00 per share.

The Corporation has a share option plan which provides for the grant of options to purchase Common Shares of the Corporation. The exercise price of each option may not be less than the closing price of the Corporation's Common Shares on the trading day immediately preceding the date of grant. Compensation expense is recognized as the options vest. Unless otherwise determined by the board of directors, vesting occurs one third on each of the next three anniversaries of the date of the grant. The options expire five years from the date of grant. The maximum number of Common Shares issuable on exercise of options outstanding at any time is limited to 10% of the issued and outstanding Common Shares.

	Year ended December 31	
Contributed Surplus	**2012 $**	**2011 $**
Balance, beginning of period	10,446	5,736
Share-based compensation expense	6,433	4,813
Transfer to share capital on exercise of options	(321)	(103)
Balance, end of period	**16,558**	**10,446**

The fair value of options granted during the year ended December 31, 2012 was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions: a risk-free interest rate of 1.2%; a dividend yield of 0%; a volatility factor of the market price of the Corporation's

Common Shares of 44%; and expected option lives of two to four years. Options granted during the year ended December 31, 2012 had an average fair value of $1.37 per option.

The fair value of options granted during the year ended December 31, 2011 was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions: a risk-free interest rate of 2.1%; a dividend yield of 0%; a volatility factor of the market price of the Corporation's Common Shares of 78.3%; and an average expected life of the options of 5 years. Options granted in 2011 had a weighted average fair value of $4.74 per option.

	Number of Options	Weighted Average Exercise Price $
Outstanding, January 1, 2011	**3,118,967**	**6.22**
Granted	1,977,500	7.57
Forfeited	(217,333)	(7.42)
Exercised	(29,999)	(6.60)
Outstanding, December 31, 2011	**4,849,135**	**6.70**
Forfeited	(86,500)	(7.67)
Exercised	(177,600)	(3.75)
Cancelled	(4,585,035)	(6.79)
Granted	8,042,000	4.49
Outstanding, December 31, 2012	**8,042,000**	**4.49**

All of the unexercised options outstanding on October 23, 2012 were cancelled, in conjunction with the Guide Arrangement (note 5), resulting in an acceleration of share-based compensation expense of $2.7 million.

The following table summarizes information regarding stock options at December 31, 2012:

Options Outstanding				Options Exercisable	
Exercise Price $	Number Outstanding	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price $	Number Exercisable	Weighted Average Exercise Price $
4.49	**8,042,000**	**4.9**	**4.49**	**-**	**-**

An estimated forfeiture rate of 10% (2011 – 9.6%) was used when recording share-based compensation expense.

Employee indemnification agreements

In December 2011, resulting from the Corporation's restriction to grant stock options to new employees due to a self-imposed trading blackout, the Corporation agreed to indemnify those employees by a one-time cash payment equal to the number of options to which the employee was entitled, multiplied by the difference between the market price of the Corporation's Common Shares at the time of indemnification ("Closing Price") and the market price at such time that the Corporation is able to grant options in accordance with applicable securities law, to the extent that the exercise price of the options granted under the plan was greater than the Closing Price. This cash payment would have been payable at the time the options granted were exercised and would have been grossed up to take into account the difference in the applicable tax treatment between an option exercise and a cash payment.

At December 31, 2011 the Corporation had issued indemnification agreements for 1,114,000 options at a Closing Price of $4.80. The fair value of the cash payment was estimated using the Black-Scholes option pricing model with the following assumptions: a dividend yield of 0%, an expected volatility of 75.7%, a risk free interest rate of 1.31%, and a weighted average life of 5.0 years. The Corporation recorded compensation expense for this arrangement during the year ended December 31, 2011 of $64,000, of which $14,000 had been capitalized.

There were no liabilities outstanding at December 31, 2012 as the indemnification agreements were cancelled on October 23, 2012 in conjunction with the completion of the Guide Arrangement (note 5) (December 31, 2011 - $0.1 million).

Performance bonus rights

In October 2010, the Corporation implemented a cash-settled performance plan based on the Corporation's Common Share price. Directors and employees were granted rights to receive a portion of a performance pool when the Corporation's Common Share price reached levels of $12.00, $15.00, and $18.00 per share. With the fair value of the plan being measured using a binomial lattice model, no liability under the performance plan was recognized at December 31, 2011. No compensation expense had been recognized under these rights, which were cancelled on October 23, 2012 in conjunction with the completion of the Guide Arrangement (note 5).

Employee long term incentives

During 2012, the Corporation established long-term incentives for employees holding certain options issued in 2011. The incentives were to provide for a cash payment to the option holder at the time of exercise of the related option. There was no expense recorded for the year ended December 31, 2012 under these incentives, which were cancelled on October 23, 2012 in conjunction with the completion of the Guide Arrangement (note 5).

Earnings (loss) per share

	Year ended December 31	
	2012	**2011**
Income (loss) during the period ($000s)	(42,652)	(52,667)
Weighted average number of shares (000s)		
Shares outstanding, beginning of period	82,969	39,935
Issue of shares for cash	-	3,956
Share options exercised	15	24
Issue of shares under Guide Arrangement	8,142	-
Issue of shares for corporate acquisition	-	19,227
Weighted average number of shares for the period	91,126	63,142
Basic and diluted loss per share	($0.47)	($0.83)

The diluted weighted average number of shares is calculated by assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase common shares of the Corporation at their average market price during the period. For the year ended December 31, 2012 potential shares from all outstanding options have been excluded from the calculation of diluted loss per share.

13. GENERAL AND ADMINISTRATION EXPENSES

$	Year ended December 31 2012	2011
Salary and employee	26,085	6,704
Other	17,981	7,669
Gross expenses	44,066	14,373
Capitalized overhead	(6,704)	(3,501)
Operating recoveries	(628)	(362)
General and administration expenses	**36,734**	**10,510**

Salary and employee costs of $12.1 million, and other general and administration expenses of $8.1 million, were incurred during the year ended December 31, 2012, relating to the Guide Arrangement on October 23, 2012 (note 5).

Long Run has determined that the key management personnel of the Corporation consist of its vice-presidents and directors. Key management personnel compensation is comprised of the following:

$	Year ended December 31 2012	2011
Wages, salaries and short-term benefits	5,939	2,581
Termination benefits	3,843	-
Included in general and administration expenses	9,782	2,581
Share-based compensation (note 12)	3,215	301
	12,997	**2,882**

14. INCOME TAXES

The components of the deferred income tax asset are as follows:

	December 31, 2012 $	December 31, 2011 $
Scientific research and experimental development	-	1,607
Alberta royalty tax deduction	1,190	-
Property and equipment	71,929	689
Investment tax credits	13,649	15,468
Share issue costs	2,048	1,863
Decommissioning liabilities	45,767	10,079
Non-capital losses	21,192	7,694
Financial derivatives	1,517	1,626
Deferred compensation	-	1,210
Other	-	346
Deferred income tax asset	**157,292**	**40,582**

Movements in the deferred tax asset during the year were as follows:

	$	$
Balance, beginning of year	40,582	58,927
Acquisitions	-	(27,298)
Guide Arrangement	107,110	-
Share issue costs	-	852
Flow-through share spending	(432)	(1,253)
Current year provision	10,032	9,354
Balance, end of year	157,292	40,582

The Canadian federal tax rate was reduced by 1.5%, from 16.5% to 15.0% on January 1, 2012. There have been no significant changes to the relevant Canadian provincial tax rates during the period.

The provision for income tax differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate of 25.1% (December 31, 2011 – 27.5%).

	Year ended December 31	
$	**2012**	**2011**
Loss before income tax	(52,017)	(61,734)
Corporate tax rate	25.1%	27.5%
Expected tax recovery	(13,077)	(16,977)
Increase (decrease) in taxes resulting from:		
Share-based compensation	1,430	1,029
Statutory tax rate changes	-	5,435
Impairment of goodwill	499	-
Non-deductible items	1,023	-
Deductible capital taxes	(184)	(76)
Other	277	1,235
Deferred income tax recovery	**(10,032)**	**(9,354)**

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax losses can be utilized. The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the Corporation's future operating results.

At December 31, 2012 the Corporation has non-capital loss carry forward balances of approximately $84.0 million, of which $0.6 million expire in 2015, with the remainder beginning to expire in 2026.

Investment tax credit balances expire as follows: December 31, 2019 – $1.3 million, December 31, 2020 – $3.0 million, December 31, 2021 – $3.8 million, December 31, 2022 – $3.1 million, December 31, 2023 – $3.5 million, and December 31, 2024 – $3.5 million.

15. RELATED PARTY TRANSACTIONS

A director of the Corporation and the corporate secretary are partners of the Corporation's legal counsel, Burnet, Duckworth & Palmer LLP ("BDP"). For the year ended December 31, 2012, general and administrative expenses and share issue costs included amounts of $1.9 million (2011 - $0.3 million) and $Nil (2011 - $0.7 million), respectively, charged to the Corporation by BDP.

16. COMMITMENTS AND CONTINGENCIES

$	Total	2013	2014	2015	2016	2017	Thereafter
Operating leases	11,884	3,003	3,076	2,672	2,089	1,044	-
Firm transportation agreements	5,715	3,167	2,030	437	81	-	-
Vehicle leases	113	113	-	-	-	-	-
Capital commitments	9,374	9,374	-	-	-	-	-
Total	27,086	15,657	5,106	3,109	2,170	1,044	-

At December 31, 2012 the Corporation is committed to future minimum lease payments of $11.9 million under operating leases for office space, and to future vehicle minimum lease payments of $0.1 million through eleven months ending November 30, 2013.
At December 31, 2012 the Corporation is committed to $5.7 million in firm contracts relating to the transportation of natural gas.

At December 31, 2012 the Corporation has entered into contracts for drilling rig services under which the Corporation is committed to using services totaling $9.4 million during the eleven months ending November 30, 2013.

Litigation

The Corporation is involved in various claims and legal actions arising in the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

17. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

Fair value of financial assets and liabilities

The Corporation's financial instruments recognized in the statement of financial position consist of accounts receivable, deposits and prepaid expenses, accounts payable, bank loan and financial derivatives ("financial instruments"). The carrying value of accounts receivable, deposits and prepaid expenses, and accounts payable approximated their fair values at December 31, 2012 due to their short-term nature. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facility. The fair value of the financial derivatives is recognized on the statement of financial position as described below.

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 are subject to normal credit risks. A portion of the Corporation's production is currently sold through joint venture partners under normal industry sale and payment terms. During 2012 and 2011, three third party purchasers each marketed at least 10% of the Corporation's petroleum and natural gas revenues. As at December 31, 2012, approximately 39% of the accounts receivable balance is due from three customers, compared to 80% due from three customers at December 31, 2011. These customers are considered to have high credit worthiness. The Corporation generally grants unsecured credit but routinely assesses the financial strength of its customers and joint venture partners. No provision has been made for past due receivables as of December 31, 2012 as the Corporation has assessed there are no impaired receivables.

At December 31	2012 $	2011 $
Less than 90 days	45,248	25,011
Greater than 90 days	3,664	2,447
Total	48,912	27,458

Liquidity risk

Liquidity risk arises through excess financial obligations due over available financial assets at any point in time. The Corporation's objective in managing liquidity risk is to maintain sufficient capital in order to meet its liquidity requirements at any point in time. The Corporation believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and to undrawn committed credit facilities to meet current spending forecasts.

Interest rate risk

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair value of its financial instruments. 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. Given the amount of debt employed, the Corporation's strategy may include managing interest rate risk through the use of interest rate swaps. Based upon the interest rate swap outstanding as at December 31, 2012, a one percent change in the interest rate would be expected to impact the unrealized gain on financial derivatives by approximately $0.8 million (December 31, 2011 - $Nil).

Market risk

Market risk is the risk of 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.

When assessing the potential impact of price changes on financial derivative contracts outstanding at December 31, 2012, it is estimated that a $1.00/Bbl change in the price of oil would change the unrealized gain at December 31, 2012 by approximately $2.4 million, while a $0.10/GJ change in the price of natural gas would change the unrealized gain at December 31, 2012 by approximately $1.5 million.

Financial derivative contracts

The Corporation has the following financial contracts in place as at December 31, 2012:

Natural Gas:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	3,000 GJ/d	CDN $2.80 - $3.40/GJ
January 1, 2013 – December 31, 2013	7,000 GJ/d	CDN $3.15 - $3.60/GJ
Fixed Price:		
January 1, 2013 – October 31, 2013	5,000 GJ/d	CDN $4.20/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.00/GJ
January 1, 2013 – December 31, 2013	5,000 GJ/d	CDN $3.50/GJ
January 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $3.60/GJ
April 1, 2013 – December 31, 2013	10,000 GJ/d	CDN $4.05/GJ
Call Swaption:		
January 1, 2014 – December 31, 2014	10,000 GJ/d	CDN $4.00/GJ

Crude Oil:	Volume	Pricing
Costless Collars:		
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$94.25/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $85.00-$96.00/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $98.00-$102.00/Bbl
Fixed Price:		
January 1, 2013 – December 31, 2013	600 Bbl/d	WTI CDN $97.05/Bbl
January 1, 2013 – December 31, 2013	1,600 Bbl/d	WTI CDN $100.30/Bbl
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI US$85.00/Bbl
Calls:		
January 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl
January 1, 2013 – December 31, 2013	73 Bbl/d	WTI US $100.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $100.00/Bbl
Call Swaptions:		
January 1, 2014 – August 31, 2014	980 Bbl/d	WTI US $85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$85.00/Bbl
September 1, 2014 – April 30, 2015	1,000 Bbl/d	WTI US$90.00/Bbl

Interest Rate Swap:	
Notional Amount CAD $75 million	Term: February 6, 2012 – January 5, 2014
Fixed rate 1.190% - Floating rate is reset against CAD-BA-CDOR monthly	

Electricity:	Volume	Pricing
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $67.75 MW/h
January 1, 2013 – December 31, 2014	1.5 MW/h	CDN $54.35 MW/h
January 1, 2015 – December 31, 2016	3.0 MW/h	CDN $49.50 MW/h

The Corporation has entered into the above contracts for the purpose of protecting funds flow generated from operations from the volatility of commodity prices and changes in interest rates. The Corporation recognizes the fair value of its financial derivatives on the statement of financial position each reporting period with the change in fair value recognized as an unrealized gain or loss on the statement of earnings. At December 31, 2012, the fair value is estimated to be a net liability of $6.0 million, composed of a $15.3 million short term asset, a $0.1 million long-term asset, a $9.3 million short-term liability, and a $12.1 million long-term liability. Of the total December 31, 2012 financial liability, $9.8 million relates to 2013, $8.5 million relates to 2014, and $3.1 million relates to 2015.

Included in petroleum and natural gas revenue for the year ended December 31, 2012 is $0.3 million of net revenue related to buying and selling natural gas on a daily compared to monthly index.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. The Corporation characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 - inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 - inputs other than quoted prices included in Level 1 that are observable, either directly or indirectly as of the reporting date. Level 2 valuations are based on inputs which can be observed or corroborated in the market place from sources such as the New York Mercantile Exchange and the Natural Gas Exchange.

- Level 3 - inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

The fair value determinations for the Corporation's financial derivatives at December 31, 2012 are based upon Level 3 inputs, having been provided by the counterparties with whom the transactions were completed and reviewed by the Corporation for reasonableness.

18. CAPITAL RISK MANAGEMENT

The Corporation defines capital as total debt plus equity, with equity defined as retained earnings plus share capital. The Corporation's primary capital management objective is to maintain a strong statement of financial position affording the Corporation financial flexibility to achieve goals of continued growth and access to capital. The basis for the Corporation's capital structure is dependent on the Corporation's expected business growth and changes in the business environment. The Corporation manages its capital structure and makes adjustments according to market conditions to maintain flexibility while achieving the objectives stated above.

To manage the capital structure, the Corporation may adjust capital spending, issue new shares, issue new debt or repay existing debt.

The Corporation monitors its progress through the following two measures utilizing book values: net debt to funds flow from operations and total debt to total debt and equity. Net debt to funds flow from operations is calculated as current liabilities and long term debt less current assets divided by four times the current quarter funds flow from operations. Total debt to total debt plus equity is calculated as short term debt plus long term debt divided by short term debt plus long term debt plus equity.

The Corporation's objective is to maintain net debt to funds flow from operations at or below a level of 1.5 to 1. While the Corporation may exceed this rate from time to time, efforts are made after a period of variation to bring the measure back in line.

The Corporation's strategy concerning capitalization is to utilize more equity than debt. This is measured by targeting total debt to total debt plus equity at a ratio of less than 0.4 to 1.

At December 31 ($000s except ratio amounts)	**Target Measure**	**2012**	**2011**
Components of ratios			
Current assets (excluding fair value of financial derivatives)		59,871	37,417
Liabilities (including current liabilities and bank loan, and excluding the fair value of financial derivatives)		352,994	162,170
Net debt		293,123	124,753
Total debt (bank loan)		261,173	124,000
Equity (share capital plus retained earnings (deficit))		569,124	440,048
Total capitalization (total debt plus equity)		830,297	564,048
Funds flow from operations [1] (fourth quarter times four)		153,628	119,584
Net debt/funds flow from operations	< 1.5 times	1.9	1.0
Total debt/total debt plus equity	< 0.4 times	0.3	0.2

[1] *Funds flow from operations is a non-GAAP measure and is based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures*

19. SUPPLEMENTAL CASH FLOW INFORMATION

The net change in working capital is comprised of:

	Change in year $	Working capital acquired $	Working capital non-cash $	Change in non-cash flow $
Year ended December 31, 2011:				
Source (use) of cash:				
Accounts receivable	(19,270)	19,961	-	691
Deposits and prepaid expenses	(1,898)	1,869	-	(29)
Accounts payable and accrued liabilities	15,584	(19,173)	1,713	(1,876)
	(5,584)	2,657	1,713	(1,214)
Related to operating activities				(422)
Related to investing activities				(792)
				(1,214)
Year ended December 31, 2012:				
Source (use) of cash:				
Accounts receivable	(21,454)	34,549	-	13,095
Deposits and prepaid expenses	(4,778)	3,048	-	(1,730)
Accounts payable and accrued liabilities	53,651	(60,958)	-	(7,307)
	27,419	(23,361)	-	4,058
Related to operating activities				8,121
Related to investing activities				(4,063)
				4,058

20. SUBSEQUENT EVENTS

Stock option issuance

Subsequent to December 31, 2012, the Corporation issued 1,170,000 options to purchase Common Shares of the Corporation at an exercise price of $4.37 per option.

Financial derivative contracts

Subsequent to December 31, 2012, the Corporation entered into the following financial derivative contracts:

Crude Oil:	Volume	Pricing
Costless Collars:		
February 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $90.00-$102.00/Bbl
Fixed Price:		
April 1, 2013 – December 31, 2013	1,000 Bbl/d	WTI CDN $96.75/Bbl
Calls:		
April 1, 2013 – December 31, 2013	200 Bbl/d	WTI US $85.00/Bbl
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $85.00/Bbl
January 1, 2015 – December 31, 2015	500 Bbl/d	WTI US $85.00/Bbl

Subsequent to December 31, 2012, the Corporation cancelled the following financial derivative contract:

Crude Oil:	Volume	Pricing
Calls:		
April 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl

Office lease

Subsequent to December 31, 2012, the Corporation surrendered a sublease for office space, reducing future minimum lease payments under operating leases by $2.0 million.

21. COMPARATIVE AMOUNTS

Certain prior year amounts have been reclassified to conform to the current year presentation.