GUIDE EXPLORATION LTD.

Management's Discussion and Analysis

December 31, 2011

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 Guide Exploration Ltd. ("Guide" or the "Corporation"), formerly Galleon Energy Inc., for the year ended December 31, 2011, with comparisons to the year ended December 31, 2010. The MD&A has been prepared by management and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2011 and 2010.

The Corporation prepares its financial statements in accordance with Canadian generally accepted accounting principles as set out in the Handbook of the Canadian Institute of Chartered Accountants (CICA Handbook). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards (IFRS), and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, the December 31, 2011 consolidated financial statements are the first annual financial statements prepared under IFRS.

The audited consolidated financial statements have been prepared in accordance with IFRS applicable to the preparation of financial statements, including IFRS 1 *First-time Adoption of International Financial Reporting Standards*. Subject to certain transition elections disclosed in note 21 to the audited consolidated financial statements, the Corporation has consistently applied the same accounting policies in its opening IFRS statement of financial position at January 1, 2010 and throughout all periods presented in the audited consolidated financial statements, as if these policies had always been in effect.

While the adoption of IFRS has not changed the Corporation's business activities or actual cash flow, it has resulted in adjustments to the Corporation's financial statements. The areas most impacted by the transition to IFRS are accounting for property and equipment, asset impairment testing, and income taxes. Please refer to Note 3 of the Corporation's audited consolidated financial statements for the Corporation's detailed IFRS accounting policies.

In order to allow the users of the financial statements to better understand the impact of the change to IFRS, the impact of the transition to IFRS on the Corporation's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Corporation's consolidated Canadian GAAP financial statements for the year ended December 31, 2010, are provided in note 21 of the Corporation's audited consolidated financial statements.

Comparative amounts throughout this MD&A have been restated to reflect the change in generally accepted accounting principles, other than annual information noted herein under "Annual Information" for the period prior to the transition to IFRS. In this MD&A, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

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 16, 2012.

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 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 Guide's performance. Management believes that in addition to net earnings, 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. Guide'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 Class A shares outstanding.

Guide 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, timing of completion of expansion of facilities, the expectation that the Corporation will not be taxable in 2012, and the expected continued volatility in commodity prices and stock markets.

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, Guide'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 Guide'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 Guide's website (www.guidex.ca). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Guide 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.

2011 Year in Review

The year ended December 31, 2011 proved to be challenging to the staff and management of Guide as we re-evaluated development plans and engaged a new independent Reserve Evaluator, Sproule, to evaluate our reserves in light of changed development plans.

In setting a course for 2012 and the future, we will narrow our near term development focus to oil, continue to expand our land base for future exploration and development, and maintain a strong focus on cost control and efficiencies.

Guide has focused its near term development efforts on the oil rich Triassic sediment package over its large land position in the Peace River Arch with particular emphasis on its emerging Montney oil resource play at Normandville/Girouxville.

Drilling in the second half of 2011 delineated a broad, oil rich, fairway in the Montney that we believe covers at least 40 sections. In the latter half of 2011, we broadened our window of opportunity for future oil exploration and development by adding land and plays in both conventional reservoirs and in emerging tight rock plays. The $20 million flow-through share offering which was completed in November 2011 is planned to be used in part to target shale resource plays in the Duvernay and Nordegg.

ANNUAL INFORMATION

($000s except per share and per unit amounts)	**2011**	**2010**	**2009**[3]
Financial			
Petroleum and natural gas revenue	188,191	207,831	213,144
Funds flow from operations [1]	98,585	100,478	97,393
Per share – basic	1.16	1.19	1.22
Per share – diluted	1.16	1.19	1.22
Net income (loss)	(212,807)	(1,083)	(34,572)
Per share – basic	(2.50)	(0.01)	(0.43)
Per share – diluted	(2.50)	(0.01)	(0.43)
Capital expenditures	150,495	136,330	106,095
Total assets	671,057	869,652	1,136,732
Net dispositions of oil and gas properties	8,258	114,158	8,451
Net debt [1,2]	169,894	152,861	226,859
Total non-current financial liabilities	21,797	14,980	-
Shareholders' equity	394,990	580,006	712,863
Weighted average shares outstanding			
Basic	85,192,616	84,770,976	79,656,109
Diluted	85,192,616	84,770,976	79,656,109

[1] *See "Non-GAAP Measurements"*
[2] *Net debt includes bank indebtedness and working capital, but excludes financial derivatives and other liability*
[3] *All 2009 amounts are as reported under Canadian GAAP and are not adjusted for IFRS*

Guide Exploration Ltd. was incorporated under the Business Corporations Act of Alberta on March 27, 2003 as Galleon Energy Inc. On November 1, 2011 the name of the Corporation was changed to Guide Exploration Ltd.

Total petroleum and natural gas revenue, before royalties and financial derivatives, was $188.2 million in 2011, a decrease of $19.6 million from $207.8 million in 2010. Although prices for crude oil increased during 2011, the benefit was offset by lower production volumes and a decrease in gas prices. Production in 2011 averaged 12,040 BOE/d compared to 14,800 BOE/d in 2010. The 19% reduction relates primarily to a decline in natural gas production, reflecting the Corporation's capital program being weighted towards oil projects. In addition, average production during the year ended December 31, 2010 included 745 BOE/d attributable to the Puskwa light oil properties sold in the second quarter of 2010.

The average price for natural gas, before transportation and financial derivative contracts, was $3.84/Mcf in 2011, 9% lower than the $4.23/Mcf price received in 2010. Crude oil prices increased 17% in 2011 to $82.70/Bbl from $70.71/Bbl in 2010.

Funds flow from operations of $98.6 million in 2011, which was 1.9% lower than in the year ended December 31, 2010, included an increase of $12.5 million in realized gains on financial derivative contracts. The $24.9 million gain realized on natural gas derivative contracts, which increased $10.3 million from 2010, raised the effective gas price received during the year by $1.43/Mcf to $5.27/Mcf, before transportation.

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment. The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the value of the after-tax cash flows from oil and gas reserves discounted at 10%, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally. Impairments were recorded at each of the Corporation's CGUs with the exception of Peace, resulting from a reduction in the estimated volumes of oil and gas reserves, as well as a weakening of the forward price curve for natural gas as at December 31, 2011 as compared to December 31, 2010.

Results of Operations

Year ended December 31	**2011**		**2010**	
	4,394,732 BOE		5,401,855 BOE	
($000s)		$/BOE		$/BOE
Revenues	188,191	42.82	207,831	38.47
Realized gain on financial derivatives	23,010	5.23	10,552	1.95
Royalties	(35,600)	(8.10)	(44,060)	(8.15)
GCA[1]	6,459	1.47	12,670	2.35
Transportation costs	(8,325)	(1.89)	(8,806)	(1.63)
Operating costs	(50,934)	(11.59)	(51,405)	(9.52)
Net	**122,801**	**27.94**	**126,782**	**23.47**
G&A	(15,475)	(3.52)	(14,773)	(2.73)
Restructuring costs	-	-	(1,242)	(0.23)
Interest costs	(7,575)	(1.72)	(10,086)	(1.87)
Exploration expenses	(916)	(0.21)	-	-
Capital and other taxes	(250)	(0.06)	(203)	(0.04)
Funds flow from operations[2]	**98,585**	**22.43**	**100,478**	**18.60**

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

Petroleum and Natural Gas Revenue *(before royalties)*

Year ended December 31	2011		2010	
($000s)		%		%
Light oil	84,620	45	78,943	38
Heavy oil	26,782	14	23,481	11
NGLs	9,554	5	9,379	5
Natural gas	66,971	36	95,615	46
Royalty income	264	-	413	-
Total	**188,191**	**100**	**207,831**	**100**

Revenues for the year ended December 31, 2011 were $188.2 million, compared to $207.8 million during the prior year. Crude oil revenues increased $9.0 million, reflecting higher crude oil prices in 2011. Gas revenues decreased by $28.6 million in 2011 due to decreased production volumes and lower gas prices.

Light oil revenues were 45% of total revenues in 2011, compared to 38% in 2010.

Production

	Year ended December 31			
	2011		2010	
		%		%
Light oil (Bbls/d)	2,674	22	2,913	20
Heavy oil (Bbls/d)	1,021	9	1,065	7
NGLs (Bbls/d)	375	3	472	3
Natural gas (Mcf/d)	47,818	66	62,098	70
BOE/d (6:1)	**12,040**	**100**	**14,800**	**100**

Average production was 12,040 BOE/d during 2011, 19% lower than the average production of 14,800 BOE/d in 2010. By product, production volumes decreased as follows: light oil production by 8%, heavy oil production by 4%, natural gas liquids production by 21% and natural gas production by 23%.

In 2011 oil and NGLs accounted for 34% of average daily production compared with 30% in 2010. In addition, average production during the year ended December 31, 2010 included 745 BOE/d attributable to the Puskwa light oil properties sold in the second quarter of 2010.

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, Guide has entered into several natural gas and crude oil financial contracts.

The Corporation has the following financial contracts in place as at December 31, 2011:

Natural Gas:		
January 1, 2012 – December 31, 2012	22,500 GJ/d	CDN $5.00/GJ
April 1, 2012 – October 31, 2012	5,000 GJ/d	CDN $4.86/GJ
Crude Oil:		
Costless Collars:		
January 1, 2012 – December 31, 2012	500 Bbl/d	WTI CDN $85.00-$90.00/Bbl
Other:		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl Call
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI US $85.00/Bbl Swaption
January 1, 2013 – December 31, 2013	73 Bbl/d	WTI US $100.00/Bbl Call
January 1, 2014 – December 31, 2014	980 Bbl/d	WTI US $85.00/Bbl Swaption
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $100.00/Bbl Call
Interest Rate Swap:		
Notional Amount CAD $50 million		Term: August 5, 2011 – August 5, 2013
Fixed rate 1.34% - Floating rate is reset against CAD-BA-CDOR on each 3 month anniversary		

During 2011, Guide recorded realized gains of $23.0 million on financial contracts, compared to gains of $10.6 million in 2010. Spot prices for natural gas continued to be substantially lower than the prices Guide has secured using financial contracts. During the year ended December 31, 2011, oil contracts for 2012 were unwound, for which a cash payment of $3.9 million was received.

Based on the mark to market value at December 31, 2011, an unrealized loss on financial contracts of $0.5 million was recorded in 2011, compared to an unrealized gain of $9.0 million in 2010. If the contracts were unwound at December 31, 2011, the Corporation would owe a net amount of $1.1 million.

Subsequent to December 31, 2011, the Corporation entered into the following commodity financial derivative transactions:

Natural Gas:		
New contracts		
March 1, 2012 – December 31, 2012	5,000 GJ/d	CDN $4.50/GJ
March 1, 2012 – December 31, 2012	5,000 GJ/d	CDN $4.50/GJ
Crude Oil:		
Other:		
Contracts unwound		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $85.00/Bbl Put
Fixed Price:		
New contracts		
February 1, 2012 – February 29, 2012	1,000 Bbl/d	WTI US $91.25/Bbl
March 1, 2012 – June 30, 2012	1,000 Bbl/d	WTI CDN $91.25/Bbl
March 1, 2012 – June 30, 2012	1,100 Bbl/d	WTI US $94.00/Bbl
July 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $91.25/Bbl Call
July 1, 2012 – December 31, 2012	1,100 Bbl/d	WTI US $94.00/Bbl Call
Costless Collar:		
New contract		
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $98.00-$102.00/Bbl

The new fixed price oil contracts have initial terms to June 30, 2012, at which time the counterparties may elect to extend the term of these contracts to December 31, 2012.

Also subsequent to December 31, 2011, the $50 million interest rate swap at 1.34% was unwound and a new contract was entered into with the following terms:

Interest Rate Swap:	
Notional Amount CAD $75 million	Term: February 6, 2012 – January 5, 2014
Fixed rate 1.19% - Floating rate is reset monthly against CAD-BA-CDOR	

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

	Year ended December 31	
	2011	**2010**
Light oil ($/Bbl)	86.85	74.50
Heavy oil ($/Bbl)	71.81	60.41
NGLs ($/Bbl)	69.80	54.44
Natural gas ($/Mcf)	3.84	4.23

Prices realized in 2011 were higher for crude oil and NGLs, and lower for natural gas. Light oil prices increased 17%, heavy oil prices increased 19%, and NGL prices increased by 28%. The average price received for natural gas decreased by 9%.

The average gas price received by Guide during 2011 was $0.24/Mcf higher than the weighted average AECO price during the year, due to the heat content of the gas. The weighted average premium to AECO received in 2010 averaged $0.21/Mcf.

During the year ended December 31, 2011, the average light oil price received by Guide was approximately $8.00/Bbl lower than the weighted average posted Edmonton light oil par price, and the average heavy oil price received by the Corporation was approximately $23.00/Bbl lower than the weighted average posted Edmonton light oil par price. During 2010, the average light and heavy oil prices received by the Corporation were approximately $3.00 and $17.00 lower than the weighted average posted Edmonton light oil par price, respectively. The year over year changes reflect Guide's changing crude slate and the changing crude oil differentials seen in Western Canada.

During 2011 Guide realized a higher net commodity price for natural gas, and a lower net commodity price for crude oil, as a result of financial derivative contracts in place. The net price received for natural gas in 2011 was $1.43/Mcf or 37% higher due to financial derivative contracts. The 2011 net price received for crude oil was $1.43/Bbl or 1.7% lower due to financial derivative contracts.

Crude Oil Prices

Year ended December 31	**2011**		**2010**	
	$000s	$/Bbl	$000s	$/Bbl
Crude oil	111,536	82.70	102,664	70.71
Realized financial contracts	(1,920)	(1.43)	(3,811)	(2.63)
Transportation	(2,945)	(2.18)	(1,831)	(1.26)
Net crude oil	106,671	79.09	97,022	66.82

Natural Gas Prices

Year ended December 31	**2011**		**2010**	
	$000s	$/Mcf	$000s	$/Mcf
Natural gas	67,101	3.84	95,788	4.23
Realized financial contracts	24,932	1.43	14,646	0.65
Transportation	(5,312)	(0.30)	(6,967)	(0.31)
Net natural gas	86,721	4.97	103,467	4.57

NGL Prices

Year ended December 31	**2011**		**2010**	
	$000s	$/Bbl	$000s	$/Bbl
NGL	9,554	69.80	9,379	54.44
Transportation	(68)	(0.50)	(8)	(0.05)
Net NGL	9,486	69.30	9,371	54.39

Performance by Property

Year ended December 31

	2011				2010			
	Production		Operating netbacks/ BOE [1]	Funds flow from operations[2]	Production		Operating netbacks/ BOE[1]	Funds flow from operations[2]
	BOE/d	%	$	%	BOE/d	%	$	%
Peace	6,845	57	22.42	60	7,672	52	18.59	51
Smoky	2,859	24	19.57	22	3,483	24	18.95	23
Cherhill	973	8	25.85	10	1,063	7	20.10	8
Worsley	563	5	7.80	2	857	6	7.89	2
Other	800	6	20.88	6	1,725	11	26.66	16
	12,040	**100**	**21.24**	**100**	**14,800**	**100**	**19.11**	**100**

[1] Operating netbacks/BOE exclude GCA and hedging gains and losses, and are calculated by subtracting royalties, operating costs, and transportation from revenues and dividing the result by the average production for the period
[2] See "Non-GAAP Measurements"

Peace Area - Includes Normandville, Girouxville, and Eaglesham

Peace area production averaged 2,257 Bbl/d of oil and NGLs and 27.5 Mmcf/d of natural gas during 2011. During the same period in 2010, production averaged 1,904 Bbl/d of oil and NGLs and 34.6 Mmcf/d of natural gas. The area contributed 60% to total funds flow from operating activities in 2011 based on 57% of production volumes. During 2011, crude oil and liquids production increased by 19% in the Peace area compared to 2010.

During the second half of 2010 Guide confirmed the viability of oil in the Normandville/Girouxville Montney fairway. This oil project was further advanced during 2011 with the drilling of 25 Montney oil wells. Guide plans to continue with this development in 2012 with a similar level of drilling activity, as well as a facility expansion.

A total of 39 (38.5 net) wells were drilled in the Peace area in 2011, of which 13 (12.7 net) wells were drilled in the fourth quarter. Up to a total of 30 (30.0 net) oil wells are planned in 2012.

Smoky Area – Includes Kakut

The Smoky area production averaged 497 Bbl/d of oil and NGLs and 14.2 Mmcf/d of natural gas during 2011. During the same period in 2010, production averaged 420 Bbl/d of oil and NGLs and 18.4 Mmcf/d of natural gas. In 2011, the Smoky area contributed 22% of funds flow from operations and 24% of production volumes.

The Corporation plans to continue drilling on this project at a measured pace and to closely monitor results. One (1.0 net) well was drilled within the Smoky area during the fourth quarter. In 2012 Smoky area activity will focus on mid-Montney oil at Bezanson and deep natural gas at Smoky Heights as well as the potential of the Duvernay shale in the area.

Cherhill Area - Includes Alexis and St Anne

Production in the Cherhill area averaged 619 Bbl/d of oil and NGLs and 2.1 Mmcf/d of natural gas during 2011. During the same period in 2010, production averaged 688 Bbl/d of oil and NGLs and 2.2 Mmcf/d of natural gas. In 2011, the Cherhill area contributed 10% of the funds flow from operations and 8% of production volumes.

Assets at Alexis and St. Anne continue to be exploited and optimized. While no drilling occurred here during the fourth quarter, 2 (2.0 net) wells were drilled in 2011, and up to 6 (4.4 net) wells are planned for 2012.

Royalties

Year ended December 31	2011	2010
($000s, except as indicated)		
Crown	27,316	35,877
Freehold	4,644	4,063
GORR and other	3,640	4,120
Gross royalties	**35,600**	**44,060**
GCA	(6,459)	(12,670)
Net royalties	**29,141**	**31,390**
% of revenue	**18.9**	**21.2**
% of revenue net of GCA	**15.5**	**15.1**

Gross royalties were 18.9% of revenues during 2011, compared to 21.2% for the same period in 2010. By product, gross royalties were 18.4% for light oil, 16.6% for natural gas, 22.9% for heavy oil, and 28.5% for liquids. For the year ended December 31, 2010, gross royalties were 25.0% for light oil, 17.2% for natural gas, 22.6% for heavy oil, and 26.8% for liquids.

The royalty rate for light oil decreased in 2011 compared 2010, reflecting a decrease in the maximum royalty rate effective January 1, 2011.

Total royalties, net of GCA, were 15.5% during 2011, compared to 15.1% during 2010.

Under the Drilling Royalty Credit ("DRC") incentive program, the Alberta Government applied up to $200 per meter for wells spud during the period April 1, 2009 to March 31, 2011 against net crown royalties payable. As at December 31, 2011, the Corporation had received in aggregate drilling credits totaling $23.4 million which were recorded as a reduction of property and equipment.

Gain on Disposal 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, 2011 gains on disposal of assets of $4.7 million were recognized (December 31, 2010 - $nil).

During the year ended December 31, 2011, the Corporation disposed of properties in the Western Montney area of British Columbia for net proceeds of $12.7 million, resulting in a gain on disposal of $2.9 million.

Operating Costs

Year ended December 31	2011			2010		
	Production	Operating Costs		Production	Operating Costs	
	%	%	$/BOE	%	%	$/BOE
Peace	57	55	11.27	52	52	9.50
Smoky	24	15	7.15	24	13	5.15
Cherhill	8	10	13.96	7	10	13.80
Worsley	5	6	15.46	6	9	14.33
Other	6	14	24.59	11	16	13.37
	100	**100**	**11.59**	**100**	**100**	**9.52**

Operating costs were $11.59/BOE during 2011, an increase of 22% from $9.52/BOE in 2010. This increase was caused by the drop in daily production volumes, higher utility costs, and increased propane and fuel costs related to new oil wells on production.

Operating expenses by product were as follows:

Year ended December 31	2011		2010	
	($000s)	$/BOE	($000s)	$/BOE
Light oil	12,755	13.07	12,006	11.29
Heavy oil	6,913	18.54	6,016	15.47
NGLs	1,527	11.14	1,599	9.28
Natural gas	29,739	10.20	31,784	8.40
BOE	50,934	11.59	51,405	9.52

General and Administration Expenses

Year ended December 31	2011		2010	
($000s)		$/BOE		$/BOE
Gross	21,034	4.78	20,016	3.71
Capitalized overhead	(3,881)	(0.88)	(3,411)	(0.64)
Overhead recoveries	(1,678)	(0.38)	(1,832)	(0.34)
Net	**15,475**	**3.52**	**14,773**	**2.73**

Gross general and administration (G&A) expenses in 2011 included $2.3 million of costs related to restructuring and associated retiring allowances.

During the year ended December 31, 2011 gross G&A expenses by category were: salary and employee – 59%, office – 16%, consulting – 8%, computer – 6%, shareholder costs – 1%, audit, engineering and legal – 7%, and corporate – 3%.

Share-Based Compensation

Share-based compensation was a non-cash expense of $3.5 million during 2011, of which $1.0 million was capitalized. During the year ended December 31, 2010, share-based compensation expense was $6.4 million, of which $1.9 million was capitalized. Forfeitures of unvested options during 2011 resulted in a reduction of share-based compensation expense during the year.

During the year ended December 31, 2011, the Corporation granted 5,912,000 stock options at an average exercise price of $2.98, having fair values between $0.60 and $1.74 per option.

During 2011, options totalling 2,736,667, having an average exercise price of $4.97 were forfeited and 1,597,000 options with an exercise price of $6.38 were cancelled.

At December 31, 2011, there were 8,728,333 stock options outstanding at an average exercise price of $3.75 per share.

Interest

Interest expense was $7.6 million during the year ended December 31, 2011, compared to $10.1 million recorded in the same period of the prior year. The average debt balance outstanding and the effective interest rate were lower in 2011 compared to 2010. The effective interest rate during the year ended December 31, 2011 was 5.1% (December 31, 2010 – 5.8%).

As at December 31, 2011, an amount of $138.2 million was drawn against the Corporation's credit facilities, compared to $135.7 million at December 31, 2010.

Exploration Expenses

Expenditures incurred before the Corporation has obtained the legal right to explore are expensed. Seismic expenditures of $916,000, relating to lands not owned by the Corporation, were expensed in 2011.

Accretion

Accretion expense on the Corporation's decommissioning liabilities was $3.2 million during 2011, compared to $3.0 million in 2010. Using a credit adjusted risk free rate of 7% to calculate the present value of decommissioning liabilities at December 31, 2011, compared to a rate of 8% at December 31, 2010, increased the decommissioning liability by approximately $4.9 million.

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 the year ended December 31, 2011, costs of $7.5 million associated with expiring land leases were expensed, compared to $9.1 million expensed during 2010.

Depletion and Depreciation

Depletion and depreciation expense was $90.7 million or $20.63/BOE for the year ended December 31, 2011, compared to $79.9 million or $14.79/BOE for 2010. Petroleum and natural gas reserves were determined by independent reserve evaluators as at December 31, 2011.

Capital expenditures of $36.7 million (December 31, 2010 - $46.4 million) related to undeveloped land and seismic have been excluded from, and $211.4 million (December 31, 2010 - $363.0 million) of future development costs have been added into, the cost bases for depletion purposes. Estimated residual values of $23.0 million have been excluded from costs subject to depletion (December 31, 2010 - $48.6 million).

In addition, the Corporation has exploration and evaluation assets of $10.1 million which are not depleted.

Impairment of Property and Equipment

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment (December 31, 2010 - $Nil). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the value of the after-tax cash flows from oil and gas reserves discounted at 10%, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally.

Impairments were recorded at each of the Corporation's CGUs with the exception of Peace, resulting from a reduction in the estimated volumes of oil and gas reserves, as well as a weakening of the forward price curve for natural gas as at December 31, 2011 as compared to December 31, 2010.

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. Commodity prices have fluctuated widely in recent years due to global and regional factors, including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. Changes in the economic environment could result in significant changes to the discount rate used to calculate net present values.

A one percent increase in the assumed after tax discount rate would result in an additional impairment of approximately $5.0 million as at December 31, 2011, while a 10% decrease in the forward commodity price estimates would result in an additional impairment of approximately $102.0 million.

Capital and Deferred Taxes

The 2011 and 2010 current tax provisions of $250,000 and $203,000, respectively, relate to Saskatchewan capital and resource tax, and were based upon revenues earned in Saskatchewan. It is not expected that Guide will pay income taxes in 2012.

The 2011 deferred income tax recovery was $43.1 million on a loss before tax of $255.7 million. A deferred income tax asset of $20.7 million was not recognized at December 31, 2011. A deferred income tax recovery of $10.9 million on a loss before tax of $11.7 million was recorded in 2010. The 2010 income tax recovery included an $11.8 million benefit relating to the disposal of properties.

Capital Expenditures

Exploration and evaluation assets, property and equipment	($000s)
Balance at December 31, 2010	816,647
Additions	150,495
Disposals	(10,676)
Acquisitions	7,150
Net decommissioning liability additions	6,003
Capitalized share-based compensation	1,005
Derecognition expense	(7,538)
Non-monetary transactions	123
Depletion and depreciation	(90,666)
Impairment of property and equipment	(255,000)
Balance at December 31, 2011	**617,543**

Capital expenditures during 2011 were $150.5 million. Drilling and completions expenditures comprised 68% of capital activity. The Corporation drilled 54 (49.5 net) wells, resulting in 11 (10.6 net) natural gas wells and 43 (38.9 net) oil wells, for a success rate of 100% during the year.

On August 4, 2011, the Corporation purchased interests in certain natural gas properties in the Smoky area for cash consideration of approximately $6.9 million including closing adjustments.

On August 31, 2011, properties in the Western Montney area of British Columbia were disposed of for net proceeds of $12.7 million, resulting in a gain on disposal of $2.9 million.

Year ended December	**2011**		**2010**	
($000s)		%		**%**
Land	13,180	9	6,807	5
Geological and geophysical	4,488	3	2,354	2
Drilling and completion	101,652	68	104,663	77
Plant and facilities	29,169	19	22,634	16
Inventory	1,267	1	(240)	-
Other assets	739	-	112	-
Capital expenditures	**150,495**	100	**136,330**	100

Liquidity and Capital Resources

As at December 31	**2011**	**2010**
($000s)		
Bank debt	138,248	135,682
Working capital deficiency [1]	31,646	17,179
Total net debt [2]	**169,894**	**152,861**

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

Funding of Capital Program

Year ended December 31	**2011**	**2010**
($000s)		
Issuance of common shares, net of costs	30,104	337
Repurchase of common shares	(2,417)	(4,154)
Funds flow from operations [1]	98,585	100,478
Change in bank debt	2,566	(81,561)
Change in financing lease	-	(1,545)
Acquisition of properties	(7,150)	(17,791)
Disposals of properties	15,408	131,949
Change in working capital and other	13,399	8,617
	150,495	**136,330**

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

On September 16, 2011, the Corporation issued 2,300,000 units ("Units") for gross proceeds of $6.5 million under a private placement to the new management group of the Corporation and their designates. Each Unit consisted of one Class A share of the Corporation and one share purchase warrant ("Warrant"). Each Warrant entitles the holder to acquire one Class A share of the Corporation

at an exercise price of $3.10 for a period of three years. The Warrants are not exercisable until the twenty day volume weighted average trading price of the Class A shares exceeds $5.00 per share.

On November 16, 2011 the Corporation issued 1,515,152 flow-through Class A shares at $3.30 per share by way of a private placement for gross proceeds of $5.0 million. The Corporation was required to incur qualifying development expenses of $5.0 million prior to December 31, 2011. As of December 31, 2011, all of the required qualifying expenditures had been incurred.

On November 24, 2011 the Corporation issued 5,634,000 flow-through Class A shares at $3.55 per share for gross proceeds of $20.0 million. The Corporation is required to incur qualifying exploration expenses of $20.0 million prior to December 31, 2012. As of December 31, 2011, $2.0 million of the required qualifying expenditures had been incurred.

During the year ended December 31, 2011, under the Normal Course Issuer Bid, the Corporation purchased 1,022,100 Class A shares for $2,417,000, of which all shares were cancelled at December 31, 2011.

Subsequent to December 31, 2011, the Corporation entered into an agreement with a syndicate of underwriters to issue, on a bought deal basis, 12,000,000 Class A shares at a price of $3.05 per share for aggregate proceeds, before share issue costs, of $36.6 million. Closing of the offering occurred on January 24, 2012.

On January 31, 2012, the Corporation purchased interests in certain natural gas properties in the Boyer area of Alberta for cash consideration of $61.5 million. At December 31, 2011, a deposit of $6.1 million had been paid towards the transaction.

On February 15, 2012, the Corporation purchased interests in certain petroleum and natural gas properties in the Peace area of Alberta for cash consideration of $6.0 million.

Subsequent to December 31, 2011, the Corporation entered into an agreement to dispose of properties in the Senex area of Alberta for cash consideration of $11.0 million before closing adjustments, a 3% royalty interest, and reimbursement for a recently completed horizontal well. The transaction is expected to close on March 30, 2012.

The Corporation has $250 million in credit facilities available, consisting of a $225 million extendible 364 day revolving term facility and a $25 million non-revolving facility. The $25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for $500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At December 31, 2011, an amount of $138.2 million was drawn against the revolving credit facility. (December 31, 2010 - $135.7 million).

The facilities bear interest at the bank's prime or banker's acceptance rates plus a rate margin. The margins range from 1.25% per annum to 5.25% per annum, based upon the Corporation's debt to cash flow ratio. For the year ended December 31, 2011, the effective interest rate was 5.1% (December 31, 2010 – 5.8%).

An annual review is scheduled to occur on or before May 28, 2012. The level of the borrowing base will be 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 will be different than that utilized by the Corporation's independent reserve evaluator.

Sensitivity Analysis

The following table shows sensitivities to 2012 budgeted funds flow from operations as a result of fluctuations in product prices, production volumes and other market factors. The table is based on budgeted 2012 production volumes, adjusted for the January 31, 2012 acquisition of properties.

Change to annual funds flow from operations	Change	$000s	$/share[2]
Price per barrel of oil (US$ WTI)[1]	$1.00	700	0.01
Price per mcf of natural gas (C$ AECO)[1]	$0.10	800	0.01
Oil production volumes	100 Bbl/d	2,200	0.02
Gas production volumes	1 Mmcf/d	300	0.00
Exchange rate (US/Canadian)	$0.01	1,300	0.01
Interest rate on debt	1%	1,100	0.01

[1] *After adjustment for estimated royalties*
[2] *Based on basic shares outstanding at December 31, 2011, adjusted for the January 24, 2012 share issuance.*

Contractual Obligations

$	Total	2012	2013	2014	2015	2016	Thereafter
Bank loan	138,248	138,248	-	-	-	-	-
Operating leases	10,065	1,830	1,830	1,830	1,830	1,830	915
Firm transportation agreements	6,135	2,810	2,027	1,028	270	-	-
Flow-through share expenditures	18,000	18,000	-	-	-	-	-
Capital commitments	1,500	1,500	-	-	-	-	-
Total	173,948	162,388	3,857	2,858	2,100	1,830	915

The Corporation has $250 million in credit facilities available, consisting of a $225 million extendible 364 day revolving term facility and a $25 million non-revolving facility. The $25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. An annual review is scheduled to occur on or before May 28, 2012. The level of the borrowing base will be 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 will be different than that utilized by the Corporation's independent reserve evaluator.

At December 31, 2011 the Corporation is committed to future minimum lease payments of $10.1 million under an operating lease for office space, and $6.1 million in firm contracts relating to the transportation of natural gas.

On November 24, 2011 the Corporation issued 5,634,000 flow-through Class A shares at $3.55 per share for gross proceeds of $20.0 million. The Corporation is required to incur qualifying exploration expenses of $20.0 million prior to December 31, 2012. As of December 31, 2011, $2.0 million of the required qualifying expenditures had been incurred.

At December 31, 2011, the Corporation has entered into contracts for drilling rig services under which the Corporation is committed to using services totaling $1.5 million during the four months ending April 30, 2012.

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.

Fourth Quarter Results

Q4 2011 compared to Q3 2011

Three months ended	**December 31 2011**		**September 30 2011**	
	1,074,473 BOE		1,076,198 BOE	
($000s)	$	$/BOE	$	$/BOE
Revenues	48,037	44.71	44,026	40.91
Realized gain (loss) on financial derivatives	4,970	4.62	9,795	9.10
Royalties	(8,625)	(8.03)	(8,290)	(7.70)
GCA[1]	943	0.88	2,612	2.43
Transportation costs	(2,021)	(1.88)	(2,041)	(1.90)
Operating costs	(12,386)	(11.53)	(12,689)	(11.79)
	30,918	**28.77**	**33,413**	**31.05**
General and administration	(3,726)	(3.47)	(4,665)	(4.34)
Interest costs	(1,798)	(1.67)	(1,874)	(1.74)
Exploration expenses	(477)	(0.44)	(23)	(0.02)
Capital and other taxes	(78)	(0.07)	(62)	(0.06)
Funds flow from operations[2]	**24,839**	**23.12**	**26,789**	**24.89**

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

Funds flow from operations decreased by $2.0 million or 7% during Q4 2011 compared to Q3 2011. Higher crude oil production volumes and prices were more than offset by a loss on oil financial derivative contracts in Q4 2011 compared to a gain in Q3 2011, as well as lower natural gas production volumes and prices during Q4 2011.

During the three months ended December 31, 2011, crude oil production and NGL averaged 4,458 Bbls/d, a 13% increase from 3,962 Bbls/d in Q3 2011. Natural gas production was 43.3 Mmcf/d in the fourth quarter of 2011, a 7% decrease from 46.4 Mmcf/d in the third quarter of 2011.

Natural gas prices, before financial derivative contracts and transportation, averaged $3.37/Mcf in Q4 2011, 13% lower than the $3.87/Mcf received in Q3 2011. Excluding transportation and financial derivative contracts, crude oil prices averaged $85.82/Bbl in Q4 2011, 12% higher than the $76.32/Bbl realized in Q3 2011.

The $4.8 million decrease in realized gains on financial derivative contracts in Q4 2011 reflects primarily a loss on oil derivative contracts in Q4 2011, compared to a gain on these contracts in Q3 2011. The $6.9 million gain on natural gas derivative contracts during the quarter resulted in a $1.73/Mcf increase in the realized gas price. The $1.9 million loss on oil derivative contracts during Q4 2011 resulted in a $5.15/Bbl decrease in the realized price for crude oil.

Operating costs were $12.4 million during the fourth quarter of 2011 and $12.7 million during Q3 2011. On a per unit basis, operating costs were $11.53/BOE in the fourth quarter of 2011, a 2% decrease from $11.79/BOE during the three months ended September 30, 2011.

Net G&A expenses of $3.7 million in Q4 2011 were 20% lower than the expenses of $4.7 million in Q3 2011, due primarily to corporate restructuring costs incurred during the third quarter.

Q4 2011 compared to Q4 2010

Three months ended December 31	**2011**		**2010**	
	1,074,473 BOE		1,247,108 BOE	
($000s)	$	$/BOE	$	$/BOE
Revenues	48,037	44.71	45,995	36.88
Realized gain (loss) on financial derivatives	4,970	4.62	1,368	1.10
Royalties	(8,625)	(8.03)	(8,555)	(6.86)
GCA[1]	943	0.88	3,042	2.44
Transportation costs	(2,021)	(1.88)	(2,085)	(1.67)
Operating costs	(12,386)	(11.53)	(12,612)	(10.11)
	30,918	**28.77**	**27,153**	**21.78**
General and administration	(3,726)	(3.47)	(4,212)	(3.38)
Interest costs	(1,798)	(1.67)	(1,645)	(1.32)
Exploration expenses	(477)	(0.44)	-	-
Capital and other taxes	(78)	(0.07)	(69)	(0.06)
Funds flow from operations[2]	**24,839**	**23.12**	**21,227**	**17.02**

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

Funds flow from operations increased by $3.6 million or 17% during Q4 2011 compared to Q4 2010. Higher crude oil production volumes and prices more than offset the impact of lower natural gas production volumes and prices. In addition, realized gains on natural gas financial derivative contracts increased $3.6 million in 2011 as compared to 2010.

For the three months ended December 31, 2011 production volumes decreased by 14% to 11,679 BOE/d from 13,556 BOE/d in the same period of the prior year. Crude oil production averaged 4,046 Bbls/d in Q4 2011, a 13% increase from 3,585 Bbls/d in Q4 2010. Natural gas production was 43.3 Mmcf/d in the fourth quarter of 2011, a 25% decrease from 57.5 Mmcf/d in the fourth quarter of 2010.

Natural gas prices, before financial derivative contracts and transportation, averaged $3.37/Mcf in Q4 2011, 12% lower than the $3.81/Mcf received in Q4 2010. Excluding transportation and financial derivative contracts, crude oil prices averaged $85.82/Bbl in Q4 2011, 19% higher than the $72.01/Bbl realized in Q4 2010.

The $3.6 million increase in realized financial derivatives in Q4 2011 reflects higher gains on natural gas derivative contracts. The $6.9 million gain on natural gas derivative contracts during the quarter resulted in a $1.73/Mcf increase in the realized gas price. The $1.9 million loss on oil derivative contracts during Q4 2011 resulted in a $5.15/Bbl decrease in the realized price for crude oil.

Operating costs were $12.4 million during the fourth quarter of 2011 and $12.6 million during Q4 2010. On a per unit basis, operating costs were $11.53/BOE in the fourth quarter of 2011, a 14% increase from $10.11/BOE during the same period of the prior year. The increase in operating costs per BOE was due primarily to the decrease in production volumes.

Net G&A expenses of $3.7 million in Q4 2011 were 12% lower than the expenses of $4.2 million in Q4 2010. In Q4 2011 net G&A expenses were $3.47/BOE, an increase of 3% compared to $3.38/BOE in Q4 2010.

Interest expense increased by $0.2 million in Q4 2011 compared to Q4 2010. A higher average debt balance outstanding during Q4 2011 was partially offset by a lower effective interest rate.

Business Risks

General

Guide 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 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, 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 activities in any 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.

Critical Accounting Policies

Adoption of IFRS

The audited consolidated financial statements have been prepared in accordance with IFRS applicable to preparation of financial statements, including IFRS 1 *First-time Adoption of International Financial Reporting Standards*. Prior to January 1, 2011, the Corporation prepared its financial statements in accordance with Canadian GAAP. While the adoption of IFRS has not changed the Corporation's business activities or actual cash flow, it has resulted in adjustments to the Corporation's financial statements.

The areas most impacted by the transition to IFRS are accounting for property and equipment, asset impairment testing, and income taxes. Please refer to Note 3 to the of the Corporation's audited consolidated financial statements for the Corporation's detailed IFRS accounting policies.

With respect to the accounting for flow-through shares, the Corporation had indicated in the December 31, 2010 MD&A that the difference between the premium received for the tax benefits to be renounced and the deferred tax liability was expected to be recorded as a tax expense on the effective date of the renouncement. In the Corporation's IFRS audited consolidated financial statements, the tax expense is recorded when the expenditures are incurred and the renouncement has been filed.

In order to allow the users of the financial statements to better understand the impact of the change to IFRS, the Corporation's Canadian GAAP consolidated balance sheets at January 1, 2010 and December 31, 2010, the Corporation's consolidated statements of earnings (loss) and comprehensive income (loss) and the consolidated statements of cash flows for the year ended December 31, 2010 have been reconciled to IFRS, with the resulting differences explained. These reconciliations are provided in note 21 of the Corporation's audited consolidated financial statements.

Change in 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* will replace portions of IAS 27 *Consolidated and Separate Financial Statements* and interpretation SIC-12 *Consolidation – Special Purpose Entities*. The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power, and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated financial statements.

IFRS 11 Joint Arrangements

IFRS 11 *Joint Arrangements* will apply to interests in joint arrangements where there is joint control. IFRS 11 would require joint arrangements to be classified as either joint operations or joint ventures. The structure of the joint arrangement would no longer be the most significant factor when classifying the joint arrangement as either a joint operation or a joint venture. In addition, the option to account for joint ventures, previously called jointly controlled entities, using proportionate consolidation may be removed, and equity accounting may be required. Venturers would transition the accounting for joint ventures from the proportionate consolidation method to the equity method by aggregating the carrying values of the proportionately consolidated assets and liabilities into a single line item. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated financial statements.

IFRS 12 Disclosure of Interests in Other Entities

The IASB has issued IFRS 12 *Disclosure of Interests in Other Entities*, which includes disclosure requirements about subsidiaries, joint ventures, and associates, as well as unconsolidated structured entities and replaces existing disclosure requirements. This standard is effective for annual periods beginning on or after January 1, 2013. Entities will be permitted to apply any of the disclosure requirements in IFRS 12 before the effective date. The Corporation is currently assessing the impact of the new standard on the consolidated 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 Corporation has not yet assessed the impact of the new standard on the consolidated 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 separate financial statements. 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 and will provide the accounting guidance for investments in associates and to set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. The amended IAS 28 may be applied by entities that are investors with joint control of, or significant influence over, an investee. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated 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.

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 charged to property and equipment and the appropriate liability account over the expected service life of the asset. 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 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 IFRS. 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 purpose.

The adoption of IFRS impacts the Corporation's presentation of financial results and accompanying disclosures. The Corporation has evaluated the impact of the conversion to IFRS on its processes, controls and financial reporting systems and has made modifications required to its control environment.

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 Corporation's most recent interim period 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 Guide as of December 31:

	2011	2010
Class A shares outstanding		
Basic	92,407,135	83,980,083
Basic, options and warrants[1]	103,435,468	91,130,083

[1] *Includes 8,728,333 options and 2,300,000 warrants at December 31, 2011 (December 31, 2010 – 7,150,000 options and nil warrants)*

At December 31, 2011, the market value of Guide's outstanding Class A shares was $292.0 million based on the December 31, 2011 closing price of $3.16 per share. As of March 16, 2012, the number of Class A

shares outstanding was 104,407,135. As of March 16, 2012, the number of options and warrants outstanding were 9,047,333 and 2,300,000, respectively.

On December 8, 2011, the Corporation received regulatory approval from the Toronto Stock Exchange for a Normal Course Issuer Bid ("Bid") to purchase in the open market for cancellation up to a maximum of 4.6 million Class A shares of the Corporation. The Bid was effective December 13, 2011 and will terminate on December 12, 2012, or such earlier time as the Bid is completed or terminated at the option of the Corporation. Copies of the Notice are available to shareholders of Guide from Guide upon request.

During the year ended December 31, 2011, under the previous Normal Course Issuer Bid, the Corporation purchased 1,022,100 shares for $2,417,000, of which all shares were cancelled at December 31, 2011.

Additional Information

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

Quarterly Highlights (unaudited)				**2011**				**2010**
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil (Bbl/d)	3,018	2,343	2,503	2,832	2,600	2,517	3,295	3,249
Heavy oil (Bbl/d)	1,028	1,245	863	948	985	1,009	1,108	1,161
Natural Gas (Mcf/d)	43,325	46,416	48,257	53,398	57,459	59,186	67,689	64,165
Liquids (Bbl/d)	412	374	346	368	394	433	537	527
BOE/d	**11,679**	**11,698**	**11,755**	**13,048**	**13,556**	**13,823**	**16,222**	**15,631**
Total BOE produced	1,074,473	1,076,198	1,069,717	1,174,344	1,247,108	1,271,739	1,476,256	1,406,752
Daily BOE of production per million Class A shares – basic	**132**	**139**	**140**	**155**	**161**	**163**	**191**	**184**
Prices (*prior to financial derivatives and transportation charges*)								
Light oil ($/Bbl)	88.40	80.14	95.58	83.14	76.44	71.26	72.53	77.47
Heavy oil ($/Bbl)	78.23	69.16	75.80	64.08	60.32	58.13	57.76	64.91
Crude oil ($/Bbl)	85.82	76.32	90.51	78.41	72.01	67.50	68.82	74.17
Natural Gas ($/Mcf)	3.37	3.87	4.10	3.98	3.81	3.75	4.07	5.22
NGLs ($/Bbl)	70.26	66.79	74.44	67.84	58.06	49.48	53.41	56.80
Per BOE ($)								
Revenues	44.71	40.91	44.95	40.91	36.88	34.82	37.44	44.28
Royalties, net of GCA	(7.15)	(5.27)	(9.01)	(5.23)	(4.42)	(4.16)	(6.71)	(7.59)
Transportation costs	(1.88)	(1.90)	(1.93)	(1.87)	(1.67)	(1.66)	(1.64)	(1.56)
Operating costs	(11.53)	(11.79)	(12.64)	(10.51)	(10.11)	(10.20)	(9.03)	(8.88)
Net	**24.15**	**21.95**	**21.37**	**23.30**	**20.68**	**18.80**	**20.06**	**26.25**
G&A	(3.47)	(4.34)	(3.67)	(2.69)	(3.38)	(3.09)	(2.07)	(2.54)
Restructuring costs	-	-	-	-	-	(0.05)	(0.81)	-
Interest expense	(1.67)	(1.74)	(1.91)	(1.58)	(1.32)	(1.45)	(2.42)	(2.14)
Exploration expenses	(0.44)	(0.02)	(0.19)	(0.18)	-	-	-	-
Capital and other taxes	(0.07)	(0.06)	(0.05)	(0.05)	(0.06)	(0.05)	0.02	(0.07)
Realized gain (loss) on financial derivatives	4.62	9.10	3.25	4.06	1.10	1.90	3.61	1.02
Funds flow from operations [1]	**23.12**	**24.89**	**18.80**	**22.86**	**17.02**	**16.06**	**18.39**	**22.52**

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

Quarterly Highlights
(unaudited)

	2011			
	Q4	Q3	Q2	Q1
Financial ($000s)				
Petroleum and natural gas revenue, before royalties	48,037	44,026	48,086	48,042
Operating costs	(12,386)	(12,689)	(13,517)	(12,342)
General & administrative expenses	(3,726)	(4,665)	(3,928)	(3,156)
Restructuring costs	-	-	-	-
Interest expense	(1,798)	(1,874)	(2,046)	(1,857)
Impairment of property and equipment	(255,000)	-	-	-
Impairment of goodwill	-	-	-	-
Funds flow from operations [1]	**24,839**	**26,789**	**20,115**	**26,842**
Per share, basic [1]	0.28	0.32	0.24	0.32
Per share, diluted [1]	0.28	0.32	0.24	0.32
Earnings (loss)	**(227,147)**	**17,132**	**10,505**	**(13,297)**
Per share, basic	(2.57)	0.20	0.13	(0.16)
Per share, diluted	(2.57)	0.20	0.13	(0.16)
Total assets	**671,057**	**898,110**	**880,379**	**885,286**
Weighted average outstanding Class A shares-basic	88,406,663	84,364,096	83,980,083	83,980,083
Weighted average outstanding Class A shares-diluted	88,406,663	84,364,096	83,980,083	83,980,083

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

Quarterly Highlights
(unaudited)

	2010			
	Q4	Q3	Q2	Q1
Financial ($000s)				
Petroleum and natural gas revenue, before royalties	45,995	44,279	55,273	62,284
Operating costs	(12,612)	(12,978)	(13,328)	(12,487)
General & administrative expenses	(4,212)	(3,930)	(3,063)	(3,568)
Restructuring costs	-	(59)	(1,183)	-
Interest expense	(1,645)	(1,849)	(3,578)	(3,014)
Impairment of property and equipment	-	-	-	-
Impairment of goodwill	(25,333)	-	-	-
Funds flow from operations [1]	**21,227**	**20,425**	**27,146**	**31,680**
Per share, basic [1]	0.25	0.24	0.32	0.37
Per share, diluted [1]	0.25	0.24	0.32	0.37
Earnings	**(35,055)**	**577**	**14,587**	**18,808**
Per share, basic	(0.41)	0.01	0.17	0.22
Per share, diluted	(0.41)	0.01	0.17	0.22
Total assets	**869,652**	**886,847**	**861,436**	**1,010,720**
Weighted average outstanding Class A shares-basic	83,983,158	84,869,236	85,143,751	85,098,939
Weighted average outstanding Class A shares-diluted	83,983,158	84,869,236	85,143,751	85,098,939

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

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

Production in 2011 averaged 12,040 BOE/d compared to 14,800 BOE/d in 2010. The 19% reduction relates primarily to a decline in natural gas production, reflecting the Corporation's capital program being

weighted towards oil projects. In addition, the Puskwa light oil properties were sold in the second quarter of 2010.

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.

Operating costs were $11.59/BOE during 2011, an increase of 22% from $9.52/BOE in 2010. This increase was caused by the drop in daily production volumes, higher utility costs, and increased propane and fuel costs related to new oil wells on production.

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, Guide has entered into several natural gas and crude oil financial contracts. The $24.9 million gain realized on natural gas derivative contracts in 2011, which increased $10.3 million from 2010, raised the effective gas price received during the year by $1.43/Mcf to $5.27/Mcf, before transportation.

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment (December 31, 2010 - $Nil). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the value of the after-tax cash flows from oil and gas reserves discounted at 10%, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally.

GUIDE EXPLORATION LTD.

Consolidated Financial Statements

December 31, 2011

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.

"Signed"
William E Andrew
Chairman and Chief Executive Officer

"Signed"
Shivon M. Crabtree
Vice President Finance and
Chief Financial Officer

March 16, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Guide Exploration Ltd.

We have audited the accompanying consolidated financial statements of Guide Exploration Ltd. (formerly Galleon Energy Inc.), which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and January 1, 2010, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for the years ended December 31, 2011 and 2010, and a summary of significant accounting policies and other explanatory information.

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

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

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

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Guide Exploration Ltd. as at December 31, 2011 and 2010, and January 1, 2010, and its financial performance and its cash flows for the years ended December 31, 2011 and 2010 in accordance with International Financial Reporting Standards.

Ernst & Young LLP

Chartered Accountants
Calgary, Canada
March 16, 2012

GUIDE EXPLORATION LTD.
Consolidated Statements of Financial Position

($000s)	December 31, 2011	December 31, 2010	January 1, 2010
		(note 21)	*(note 21)*
ASSETS			
CURRENT			
Accounts receivable (note 16)	21,259	28,829	41,270
Deposits and prepaid expenses (note 20)	9,258	3,361	6,190
Fair value of financial derivatives (note 16)	22,997	20,815	4,241
	53,514	53,005	51,701
Exploration and evaluation assets (note 7)	10,145	-	-
Property and equipment (notes 5, 6, 8 and 10)	607,398	816,647	881,937
Goodwill (note 9)	-	-	25,333
	671,057	**869,652**	**958,971**
LIABILITIES			
CURRENT			
Accounts payable and accrued liabilities	62,163	49,369	55,531
Financing lease (note 8)	-	-	1,545
Bank loan (note 11)	138,248	135,682	217,243
Other liability (notes 12 and 21)	3,554	-	3,775
Fair value of financial derivatives (note 16)	2,250	6,411	13,789
	206,215	191,462	291,883
Decommissioning liabilities (note 10)	48,055	39,947	38,228
Fair value of financial derivatives (note 16)	21,797	14,980	-
Deferred income taxes (note 14)	-	43,257	49,245
	276,067	289,646	379,356
SHAREHOLDERS' EQUITY			
Share capital (note 12)	606,256	586,626	595,559
Contributed surplus (note 12)	48,742	40,581	30,174
Retained earnings (deficit)	(260,008)	(47,201)	(46,118)
	394,990	580,006	579,615
	671,057	**869,652**	**958,971**

See accompanying notes

Approved on behalf of the Board

"Signed"
Patricia Newson
Director

"Signed"
Brad Munro
Director

GUIDE EXPLORATION LTD.
Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss)

($000s, except per share amounts)	Year ended December 31 2011	2010
		(note 21)
INCOME		
Petroleum and natural gas revenue	188,191	207,831
Royalties, net of gas cost allowance	(29,141)	(31,390)
Realized gain on financial derivatives (note 16)	23,010	10,552
Unrealized gain (loss) on financial derivatives (note 16)	(474)	8,972
Gain on disposal of assets	4,732	-
Other income	123	334
	186,441	196,299
EXPENSES		
Operating	50,934	51,405
Transportation	8,325	8,806
General and administration (note 13)	15,475	14,773
Restructuring costs (note 19)	-	1,242
Share-based compensation (note 12)	2,509	4,447
Interest (note 11)	7,575	10,086
Exploration expenses	916	-
Accretion (note 10)	3,173	2,984
Derecognition expenses	7,538	9,069
Depletion and depreciation	90,666	79,886
Impairment of property and equipment (note 6)	255,000	-
Impairment of goodwill (note 9)	-	25,333
	442,111	208,031
Loss before taxes	(255,670)	(11,732)
Income taxes (note 14)		
Capital and other taxes	250	203
Deferred income tax recovery	(43,113)	(10,852)
	(42,863)	(10,649)
NET LOSS AND COMPREHENSIVE LOSS	**(212,807)**	**(1,083)**
NET LOSS AND COMPREHENSIVE LOSS PER SHARE (note 12)		
Basic	(2.50)	(0.01)
Diluted	(2.50)	(0.01)
Weighted average Class A shares – basic	85,192,616	84,770,976
– diluted	85,192,616	84,770,976

See accompanying notes

GUIDE EXPLORATION LTD.
Consolidated Statement of Changes in Equity

($000s)	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total
Balance, January 1, 2010 (note 21)	595,559	30,174	(46,118)	579,615
Share-based compensation (note 12)	-	6,380	-	6,380
Options exercised (note 12)	460	(123)	-	337
Shares purchased and cancelled (note 12)	(8,304)	4,150	-	(4,154)
Tax deduction of share issue costs (note 12)	(1,089)	-	-	(1,089)
Comprehensive loss	-	-	(1,083)	(1,083)
Balance, December 31, 2010 (note 21)	586,626	40,581	(47,201)	580,006
Share-based compensation (note 12)	-	3,514	-	3,514
Tax deduction of share issue costs (note 12)	(197)	-	-	(197)
Issue of common shares (note 12)	26,891	-	-	26,891
Shares purchased and cancelled (note 12)	(7,064)	4,647	-	(2,417)
Comprehensive loss	-	-	(212,807)	(212,807)
Balance, December 31, 2011	606,256	48,742	(260,008)	394,990

See accompanying notes

GUIDE EXPLORATION LTD.
Consolidated Statements of Cash Flows

($000s)	Year ended December 31 2011	2010 *(note 21)*
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net loss	(212,807)	(1,083)
Items not requiring cash:		
Deferred income tax recovery	(43,113)	(10,852)
Impairment of goodwill	-	25,333
Impairment of property and equipment	255,000	-
Depletion and depreciation	90,666	79,886
Derecognition expenses	7,538	9,069
Accretion	3,173	2,984
Share-based compensation	2,509	4,447
Other income	(123)	(334)
Gain on disposal of assets	(4,732)	-
Unrealized gain (loss) on financial derivatives	474	(8,972)
Abandonment costs	(1,068)	(491)
Change in non-cash working capital (note 18)	6,036	3,378
	103,553	103,365
FINANCING ACTIVITIES		
Issue of common shares, net of costs (note 12)	30,104	337
Repurchase of common shares (note 12)	(2,417)	(4,154)
Financing lease payments	-	(1,545)
Bank loan (repayment)	2,566	(81,561)
	30,253	(86,923)
INVESTING ACTIVITIES		
Exploration and evaluation expenditures (note 7)	(10,145)	-
Additions to property and equipment (note 8)	(140,350)	(136,330)
Acquisitions of oil and gas properties (note 8)	(7,150)	(17,791)
Disposals of oil and gas properties (note 8)	15,408	131,949
Change in non-cash working capital (note 18)	8,431	5,730
	(133,806)	(16,442)
CHANGE IN CASH	-	-
CASH, BEGINNING AND END OF PERIOD	-	-
SUPPLEMENTAL INFORMATION		
Cash interest paid	7,665	9,599
Cash taxes paid	187	371

See accompanying notes

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

1. REPORTING ENTITY

Guide Exploration Ltd. ("Guide" or the "Corporation") was incorporated under the *Business Corporations Act* (Alberta) on March 27, 2003 as Galleon Energy Inc. On November 1, 2011 the name of the Corporation was changed to Guide. The business of the Corporation is the acquisition of, exploration for and development of petroleum and natural gas properties in western Canada. Guide's outstanding Class A shares are listed on the Toronto Stock Exchange under the symbol "GO".

The financial statements include the accounts of the Corporation, its wholly owned subsidiary 1175176 Alberta Ltd and its indirect wholly owned partnership Guidex Partnership (formerly Galleon Energy Partnership), on a consolidated basis.

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

The Corporation prepares its financial statements in accordance with Canadian generally accepted accounting principles as set out in the Handbook of the Canadian Institute of Chartered Accountants (CICA Handbook). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards (IFRS), and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, these are the first annual financial statements prepared under IFRS. In these financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

These consolidated financial statements have been prepared in accordance with IFRS applicable to the preparation of financial statements, including IFRS 1 *First-time Adoption of International Financial Reporting Standards*. Subject to certain transition elections disclosed in note 21, the Corporation has consistently applied the same accounting policies in its opening IFRS statement of financial position at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect.

Note 21 discloses the impact of the transition to IFRS on the Corporation's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Corporation's consolidated Canadian GAAP financial statements for the year ended December 31, 2010. Comparative figures for 2010 in these financial statements have been restated to give effect to these changes.

The financial statements were authorized for issue by the Board of Directors on March 16, 2012.

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 16.

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.

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.

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 16). 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.

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 are classified as held-for-trading 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. There were no financial assets on the statement of financial position which were designated as available-for-sale.

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.

Proven and probable reserves represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially viable. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable and a 50 percent statistical probability that it will be less. The equivalent statistical

probabilities for the proven and probable components of proven and probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon a reasonable assessment of the future economics of such production, a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production and there is evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proven and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proven includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proven limit of the reservoir.

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 consolidated 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 credit adjusted 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.

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 has financed 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 on the flow-through shares which is initially recorded as an other liability in the statement of financial position.

Earnings (loss) per share

Basic earnings (loss) per share is 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* will replace portions of IAS 27 *Consolidated and Separate Financial Statements* and interpretation SIC-12 *Consolidation – Special Purpose Entities*. The key features of IFRS 10 include consolidation using a single control model, definition of control, considerations on power, and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated financial statements.

IFRS 11 Joint Arrangements

IFRS 11 *Joint Arrangements* will apply to interests in joint arrangements where there is joint control. IFRS 11 would require joint arrangements to be classified as either joint operations or joint ventures. The structure of the joint arrangement would no longer be the most significant factor when classifying the joint arrangement as either a joint operation or a joint venture. In addition, the option to account for joint ventures, previously called jointly controlled entities, using proportionate consolidation may be removed, and equity accounting may be required. Venturers would transition the accounting for joint ventures from the proportionate consolidation method to the equity method by aggregating the carrying values of the proportionately consolidated assets and liabilities into a single line item. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated financial statements.

IFRS 12 Disclosure of Interests in Other Entities

The IASB has issued IFRS 12 *Disclosure of Interests in Other Entities*, which includes disclosure requirements about subsidiaries, joint ventures, and associates, as well as unconsolidated structured entities and replaces existing disclosure requirements. This standard is effective for annual periods beginning on or after January 1, 2013. Entities will be permitted to apply any of the disclosure requirements in IFRS 12 before the effective date. The Corporation is currently assessing the impact of the new standard on the consolidated 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 Corporation has not yet assessed the impact of the new standard on the consolidated 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 separate financial statements. 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 and will provide the accounting guidance for investments in associates and to set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. The amended IAS 28 may be applied by entities that are investors with joint control of, or significant influence over, an investee. These amendments are effective for annual periods beginning on or after January 1, 2013 and early adoption is permitted. The Corporation is currently assessing the impact of the new standard on the consolidated financial statements.

5. BUSINESS COMBINATIONS

On August 4, 2011 the Corporation purchased interests in certain natural gas properties in the Smoky area of Alberta. Details of the transaction are as follows:

	$
Property and equipment	7,270
Decommissioning liabilities	(400)
Identifiable net assets acquired	6,870
Cash consideration paid	6,870

The consolidated financial statements incorporate the operations of the acquired properties commencing August 4, 2011. During the period August 4, 2011 to December 31, 2011, the Corporation recorded petroleum and natural gas revenue of $1.4 million and net income of $Nil in respect of these assets. Had the transaction closed on January 1, 2011, the incremental revenue and net income reported by the Corporation would have been approximately $1.6 million and $0.2 million, respectively (unaudited).

6. IMPAIRMENT OF PROPERTY AND EQUIPMENT

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment (December 31, 2010 - $Nil). 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.

The net present values of the cash flows from oil and gas reserves at December 31, 2011 were calculated using an after-tax discount rate of 10%, a US$/CDN$ exchange rate of 0.99, and the following forward commodity price estimates:

Year	WTI Oil (US$/bbl)	AECO Gas (CDN$/mcf)
2012	98.14	3.41
2013	98.60	4.05
2014	99.01	4.53
2015	101.08	5.21
2016	102.33	5.56
2017	103.61	5.91
2018	105.23	6.19
2019	107.04	6.42
2020	108.89	6.68
2021	111.09	6.86
2022	113.30	6.99
Remainder	+2% per year	+2% per year

Impairments were recorded at each of the Corporation's CGUs with the exception of Peace, resulting from a reduction in the estimated volumes of oil and gas reserves, as well as a weakening of the forward price curve for natural gas as at December 31, 2011 as compared to December 31, 2010.

A one percent increase in the assumed after tax discount rate would result in an additional impairment of approximately $5.0 million as at December 31, 2011, while a 10% decrease in the forward commodity price estimates would result in an additional impairment of approximately $102.0 million.

7. EXPLORATION AND EVALUATION ASSETS

	$
Balance, January 1, 2010 and December 31, 2010	-
Additions	10,145
Balance, December 31, 2011	**10,145**

8. PROPERTY AND EQUIPMENT

Cost	Petroleum & natural gas properties $	Office furniture & equipment $	Total $
Balance, January 1, 2010	1,045,877	2,553	1,048,430
Additions	136,219	111	136,330
Acquisitions	17,791	-	17,791
Disposals	(131,949)	-	(131,949)
Capitalized share-based compensation	1,933	-	1,933
Derecognition expense	(9,069)	-	(9,069)
Non-monetary transactions	334	-	334
Decommissioning liabilities	(774)	-	(774)
Balance, December 31, 2010	1,060,362	2,664	1,063,026
Additions	139,611	739	140,350
Acquisitions	7,150	-	7,150
Disposals	(10,676)	-	(10,676)
Capitalized share-based compensation	1,005	-	1,005
Derecognition expense	(7,538)	-	(7,538)
Non-monetary transactions	123	-	123
Decommissioning liabilities	6,003	-	6,003
Balance, December 31 , 2011	1,196,040	3,403	1,199,443

Accumulated depletion, depreciation & impairments	Petroleum & natural gas properties $	Office furniture & equipment $	Total $
Balance, January 1, 2010	165,319	1,174	166,493
Depletion & depreciation expense	79,586	300	79,886
Balance, December 31, 2010	244,905	1,474	246,379
Depletion & depreciation expense	90,363	303	90,666
Impairment (note 6)	255,000	-	255,000
Balance, December 31, 2011	590,268	1,777	592,045

Net book value	Petroleum & natural gas properties $	Office furniture & equipment $	Total $
Balance, January 1, 2010	880,558	1,379	881,937
Balance, December 31, 2010	815,457	1,190	816,647
Balance, December 31, 2011	605,772	1,626	607,398

As at December 31, 2011, $36.7 million (December 31, 2010 - $46.4 million) of undeveloped land and seismic have been excluded from, and $211.4 million (December 31, 2010 - $363.0 million) in

future development costs have been added into, the cost bases for depletion purposes. Estimated residual values of $23.0 million have been excluded from costs subject to depletion (December 31, 2010 - $48.6 million).

For the year ended December 31, 2011, $1.2 million (December 31, 2010 – $1.3 million) of geological and geophysical related salaries have been capitalized.

During the year ended December 31, 2011 the Corporation disposed of properties in the Western Montney area of British Columbia for net proceeds of $12.7 million, resulting in a gain on disposal of $2.9 million.

At December 31, 2011, the Corporation had recorded drilling credits in aggregate of $23.4 million as a reduction of property and equipment (December 31, 2010 - $20.9 million).

During the year ended December 31, 2010 the Corporation sold properties in the Puskwa area of Alberta for cash consideration, net of adjustments, of $131.4 million.

During the year ended December 31, 2010 the Corporation purchased non-producing assets in the Smoky area of Alberta for cash consideration of $17.5 million, and in 2011 purchased producing assets for $6.9 million (note 5).

The final payment required under the equipment financing leases was made during the year ended December 31, 2010.

9. GOODWILL

	Cost	Impairment Losses	Net
	$	$	$
Balance, January 1, 2010	25,333	-	25,333
Impairment	-	(25,333)	(25,333)
Balance, December 31, 2010 and December 31, 2011	25,333	(25,333)	-

The Corporation reviewed the valuation of goodwill as of December 31, 2010 and determined that the recoverable amount had declined below the carrying value. Based upon this review, an impairment of goodwill of $25.3 million was recorded as a non-cash charge to earnings as of December 31, 2010.

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 $130 million, which will be incurred over the next 40 years. A credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the decommissioning liabilities as at December 31, 2011 (December 31, 2010 – 8% and 2%, respectively).

Year ended December 31	2011 $	2010 $
Balance, beginning of period	39,947	38,228
Accretion expense	3,173	2,984
Liabilities incurred	1,726	1,985
Disposal of liabilities	(1,615)	(1,839)
Settlement of liabilities	(1,068)	(491)
Change in estimates	5,892	(920)
Balance, end of period	**48,055**	**39,947**

11. AVAILABLE CREDIT FACILITIES

The Corporation has $250 million in credit facilities available, consisting of a $225 million extendible 364 day revolving term facility and a $25 million non-revolving facility. The $25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for $500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At December 31, 2011, an amount of $138.2 million was drawn against the revolving credit facility (December 31, 2010 - $135.7 million).

The facilities bear interest at the bank's prime or banker's acceptance rates plus a rate margin. The margins range from 1.25% per annum to 5.25% per annum, based upon the Corporation's debt to cash flow ratio. For the year ended December 31, 2011, the effective interest rate, including standby and extension fees, was 5.1% (December 31, 2010 – 5.8%).

An annual review is scheduled to occur on or before May 28, 2012. As at December 31, 2011, the Corporation is in compliance with all covenants, obligations and conditions of its credit agreement.

12. SHARE CAPITAL

Authorized

Unlimited number of preferred shares with no par value
Unlimited number of voting Class A shares with no par value
Unlimited number of voting Class B shares with no par value

Issued

Class A Shares	Number of Shares	Amount $
Balance, January 1, 2010	**85,090,883**	**595,559**
Issued for cash on exercise of stock options	77,000	337
Transfer from contributed surplus on exercise of options	-	123
Shares purchased and cancelled (a)	(1,187,800)	(4,154)
Transfer to contributed surplus on cancellation of shares (a)	-	(4,150)
Tax deduction of share issue costs	-	(1,089)
Balance, December 31, 2010	**83,980,083**	**586,626**
Common shares purchased and cancelled (a)	(1,022,100)	(2,417)
Transfer to contributed surplus on cancellation of shares (a)	-	(4,647)
Issued for cash (b)	2,300,000	6,463
Issued for cash (c) (e)	1,515,152	5,000
Issued for cash (d) (e)	5,634,000	20,001
Premium received on flow-through shares (e)	-	(3,554)
Share issue costs, net of deferred tax of $341,000	-	(1,019)
Tax deduction of share issue costs	-	(197)
Balance, December 31, 2011	**92,407,135**	**606,256**

Warrants	Number of Warrants	Weighted Average Exercise Price $
Balance, January 1, 2010 and 2011	**-**	**-**
Granted (b)	2,300,000	3.10
Balance, December 31, 2011	**2,300,000**	**3.10**

a) On November 26, 2009, the Corporation received regulatory approval for a renewal of a Normal Course Issuer Bid ("Bid") with approval to purchase in the open market for cancellation up to a maximum of 1,000,000 Class A shares of the Corporation. The renewal commenced on December 1, 2009 and terminated on November 30, 2010. Regulatory approval for an amendment to the Bid, increasing the maximum number of shares that may be purchased to 2,000,000, was received on September 17, 2010.

During the year ended December 31, 2010, the Corporation purchased 1,187,800 shares for cancellation for $4,154,000, all of which were cancelled at December 31, 2010. Share capital was reduced and contributed surplus was increased by an additional $4,150,000, being the difference between the book value of the shares at the date of purchase and the purchase price of the shares.

On November 29, 2010, the Corporation received regulatory approval for a Bid to purchase for cancellation up to a maximum of 2,000,000 shares of the Corporation, effective December 1, 2010. The Bid was effective on December 1, 2010 and terminated on November 30, 2011. Regulatory approval for an amendment to the Bid, increasing the

maximum number of shares that could be purchased to 6,200,000 was received on October 7, 2011.

During the year ended December 31, 2011, the Corporation purchased 1,022,100 shares for cancellation for $2,417,000, all of which were cancelled at December 31, 2011. Share capital was reduced and contributed surplus was increased by an additional $4,647,000, being the difference between the book value of the shares at the date of purchase and the purchase price of the shares.

On December 8, 2011, the Corporation received regulatory approval from the Toronto Stock Exchange for a Normal Course Issuer Bid ("Bid") to purchase in the open market for cancellation up to a maximum of 4.6 million Class A shares of the Corporation. The Bid was effective December 13, 2011 and will terminate on December 12, 2012, or such earlier time as the Bid is completed or terminated at the option of the Corporation.

b) On September 16, 2011, the Corporation issued 2,300,000 units ("Units") for gross proceeds of $6.5 million under a private placement to the new management group of the Corporation and their designates. Each Unit consisted of one Class A share of the Corporation and one share purchase warrant ("Warrant"). Each Warrant entitles the holder to acquire one Class A share of the Corporation at an exercise price of $3.10 for a period of three years. The Warrants are not exercisable until the twenty day volume weighted average trading price of the Class A shares exceeds $5.00 per share.

c) On November 16, 2011 the Corporation issued 1,515,152 flow-through Class A shares at $3.30 per share by way of a private placement for gross proceeds of $5.0 million. The Corporation was required to incur qualifying development expenses of $5.0 million prior to December 31, 2011. As of December 31, 2011, all of the required qualifying expenditures have been incurred.

d) On November 24, 2011 the Corporation issued 5,634,000 flow-through Class A shares at $3.55 per share for gross proceeds of $20.0 million. The Corporation is required to incur qualifying exploration expenses of $20.0 million prior to December 31, 2012. As of December 31, 2011, $2.0 million of the required qualifying expenditures have been incurred.

e) The premium proceeds in excess of $3.00 per share for the flow-through shares were received for the tax benefits to be renounced under the flow-through share offerings. At December 31, 2011, $3.6 million of the premium represents the outstanding liability for the tax benefits to be incurred and renounced.

The Corporation has a share option plan which provides for the grant of options to purchase Class A shares of the Corporation. The exercise price of each option may not be less than the closing price of the Corporation's Class A shares on the day immediately prior to the date of the grant. Compensation expense is recognized as the options vest. The 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 Corporation may grant up to 10% of the aggregate number of Class A shares outstanding and no one optionee is permitted to hold options entitling such optionee to purchase more than 5% of the aggregate number of issued and outstanding Class A shares.

Contributed Surplus	Year ended December 31 2011 $	2010 $
Beginning of period	40,581	30,174
Share-based compensation expense	3,514	6,380
Transfer from share capital on cancellation of shares (a)	4,647	4,150
Transfer to share capital on exercise of options	-	(123)
End of period	**48,742**	**40,581**

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: risk-free interest rates of 1.1–2.5%; dividend yield of 0%; volatility factors of the market price of the Corporation's common shares of 44-69%; and expected option lives of two to four years. Options granted during the year ended December 31, 2011 had fair values between $0.60 and $1.74 per option.

The fair value of options granted during the year ended December 31, 2010 was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions: risk-free interest rates of 1.3–2.3%; dividend yield of 0%; volatility factors of the market price of the Corporation's common shares of 55-72%; and an average expected life of the options of 3 years. Options granted in 2010 had fair values of between $1.24 and $2.61 per option.

	Number of Options	Weighted Average Exercise Price $
Outstanding, January 1, 2010	**6,733,834**	**6.08**
Granted	2,569,000	4.30
Forfeited	(2,023,334)	(5.96)
Expired	(52,500)	(13.17)
Exercised	(77,000)	(4.38)
Outstanding, December 31, 2010	**7,150,000**	**5.44**
Granted	5,912,000	2.98
Forfeited	(2,736,667)	(4.97)
Cancelled	(1,597,000)	(6.38)
Outstanding, December 31, 2011	**8,728,333**	**3.75**

The following table summarizes information regarding stock options at December 31, 2011:

Options Outstanding				Options Exercisable	
Exercise Price $	Number Outstanding	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price $	Number Exercisable	Weighted Average Exercise Price $
2.23-3.32	5,132,000	4.7	2.91	-	-
3.49-5.22	2,068,000	3.5	4.00	893,000	4.31
5.40-6.38	1,528,333	2.9	6.23	969,667	6.29
	8,728,333	**4.1**	**3.75**	**1,862,667**	**5.34**

An estimated forfeiture rate of 10% (2010 - 10%) was used when recording share-based compensation expense.

Earnings (loss) per share

	Year ended December 31	
	2011	**2010**
Loss during the period ($000s)	(212,807)	(1,083)
Weighted average number of common shares (000s)		
Beginning of period	83,980	85,091
Issue of common shares	1,458	-
Share options exercised	-	47
Repurchase of common shares	(245)	(367)
Weighted average number of common shares – basic	85,193	84,771
Basic and diluted loss per share	($2.50)	($0.01)

The diluted weighted average number of shares is calculated 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 for the period. For the years ended December 31, 2011 and 2010, potential shares from all outstanding options have been excluded from the calculation of diluted loss per share as their inclusion is considered anti-dilutive in periods when a loss is incurred.

13. GENERAL AND ADMINISTRATION EXPENSES

	Year ended December 31	
$	**2011**	**2010**
Salary and employee	12,456	11,702
Other	8,578	8,314
Gross expenses	21,034	20,016
Capitalized overhead	(3,881)	(3,411)
Operating recoveries	(1,678)	(1,832)
General and administration expenses	**15,475**	**14,773**

Guide has determined that the key management personnel of the Corporation consist of its officers and directors. Key management personnel compensation is comprised of the following:

	Year ended December 31	
$	**2011**	**2010**
Wages and salaries	2,667	2,728
Short-term employee benefits	205	188
Termination benefits	2,339	-
Directors fees	450	530
Included in general and administration expenses	5,661	3,446
Share-based compensation (note 12)	2,515	2,850
	8,176	**6,296**

14. INCOME TAXES

The deferred tax liability comprises the following temporary differences:

	December 31, 2011 $	December 31, 2010 $	January 1, 2010 $
Property and equipment	(18,560)	43,956	56,685
Alberta royalty tax deduction	(1,190)	(1,302)	(1,260)
Share issue costs	(607)	(681)	(1,770)
Decommissioning liabilities	(1,079)	(960)	(343)
Non-capital losses	(12,799)	(23,223)	(28,932)
Partnership income tax deferral	13,807	25,612	27,749
Financing leases	-	-	(402)
Financial derivatives	(264)	(145)	(2,482)
Unrecognized deferred income tax asset	20,692	-	-
Deferred income tax liability	**-**	**43,257**	**49,245**

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 26.6% (December 31, 2010 – 28.1%).

	Year ended December 31	
$	**2011**	**2010**
Loss before income tax	(255,670)	(11,732)
Corporate tax rate	26.55%	28.05 %
Expected tax recovery	(67,880)	(3,291)
Increase (decrease) in taxes resulting from:		
Non-deductible items	46	38
Share-based compensation	735	1,247
Statutory tax rate changes	3,692	(3,647)
Share issue costs	(197)	(1,089)
Flow-through share expense	-	687
Deductible capital taxes	(70)	(84)
Impairment of goodwill	-	7,108
Disposal of properties	-	(11,821)
Unrecognized deferred income tax asset	20,692	-
Other	(131)	-
Deferred income tax recovery	**(43,113)**	**(10,852)**

At December 31, 2011 the Corporation has deductible temporary differences of approximately $132.7 million, including unused tax losses of approximately $51.0 million which begin to expire in 2027. A portion of the deferred tax asset related to these items has been recognized as an offset to the deferred tax liability associated with the partnership income tax deferral. The remaining deferred tax asset related to these items has not been recognized in the statement of financial position.

15. COMMITMENTS AND CONTINGENCIES

$	Total	2012	2013	2014	2015	2016	Thereafter
Operating leases	10,065	1,830	1,830	1,830	1,830	1,830	915
Firm transportation agreements	6,135	2,810	2,027	1,028	270	-	-
Capital commitments	1,500	1,500	-	-	-	-	-
Total	17,700	6,140	3,857	2,858	2,100	1,830	915

At December 31, 2011 the Corporation is committed to future minimum lease payments of $10.1 million under an operating lease for office space.

At December 31, 2011 the Corporation is committed to $6.1 million in firm contracts relating to the transportation of natural gas.

At December 31, 2011 the Corporation has entered into contracts for drilling rig services under which the Corporation is committed to using services totaling $1.5 million during the four months ending April 30, 2012.

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.

16. 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, accounts payable, bank loan and financial derivatives ("financial instruments"). The carrying value of accounts receivable and accounts payable approximated their fair values at December 31, 2011 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 2011, four third party purchasers each marketed at least 10% of the Corporation's petroleum and natural gas revenues. As at December 31, 2011, approximately 61% of the accounts receivable balance is due from three customers, compared to 48% due from three customers at December 31, 2010. 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, 2011 as the Corporation has assessed there are no impaired receivables.

At December 31	2011 $	2010 $
Less than 90 days	20,479	24,911
Greater than 90 days	780	3,918
Total	21,259	28,829

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 and 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. For the year ended December 31, 2011, excluding the impact on unrealized financial derivative contracts, it is estimated that a 1.0% change to the effective interest rate would have had a $1.0 million impact on net income (December 31, 2010 - $0.6 million).

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 and interest rate risk. For the year ended December 31, 2011, excluding the impact on unrealized financial derivative contracts, it is estimated that a $0.25/Mcf change in the price of natural gas would have had a $0.8 million impact on net income, (December 31, 2010 - $2.4 million). For the year ended December 31, 2011, excluding the impact on unrealized financial derivative contracts and the impact on the unwinding of financial derivative contracts, it is estimated that a $5.00 USD WTI/Bbl change in the price of oil would have had a $0.7 million impact on net income (December 31, 2010 - $0.7 million).

Financial derivative contracts

The Corporation has the following financial contracts in place as at December 31, 2011:

Natural Gas:		
January 1, 2012 – December 31, 2012	22,500 GJ/d	CDN $5.00/GJ
April 1, 2012 – October 31, 2012	5,000 GJ/d	CDN $4.86/GJ
Crude Oil:		
Costless Collars:		
January 1, 2012 – December 31, 2012	500 Bbl/d	WTI CDN $85.00-$90.00/Bbl
Other:		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2013 – December 31, 2013	1,527 Bbl/d	WTI US $85.00/Bbl Call
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI US $85.00/Bbl Swaption
January 1, 2013 – December 31, 2013	73 Bbl/d	WTI US $100.00/Bbl Call
January 1, 2014 – December 31, 2014	980 Bbl/d	WTI US $85.00/Bbl Swaption
January 1, 2014 – December 31, 2014	500 Bbl/d	WTI US $100.00/Bbl Call

Interest Rate Swap:	
Notional Amount CAD $50 million	Term: August 5, 2011 – August 5, 2013
Fixed rate 1.34% - Floating rate is reset against CAD-BA-CDOR on each 3 month anniversary	

The Corporation has entered into the above contracts for the purpose of protecting funds flow generated from operations from the volatility of commodity prices. 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, 2011, the fair value is estimated to be a net liability of $1.1 million, composed of a $23.0 million short term asset, a $2.3 million short-term liability, and a $21.8 million long-term liability. Of the total December 31, 2011 financial liability, $2.3 million relates to 2012, $15.0 million relates to 2013, and $6.8 million relates to 2014.

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 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.

17. CAPITAL RISK MANAGEMENT

The Corporation defines capital as total debt and shareholders' equity comprised of retained earnings and 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, purchase shares under the Normal Course Issuer Bid, 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 shareholders' equity. Net debt to funds flow from operations is calculated as current liabilities and long term debt less current assets divided by annual funds flow from operations. Total debt to total debt plus shareholders' equity is calculated as short term debt plus long term debt divided by short term debt plus long term debt plus shareholders' equity. The Corporation has no externally imposed capital requirements.

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 shareholders' equity at a ratio of less than 0.4 to 1.

At December 31 ($000s except ratio amounts)	Target Measure	2011	2010
Components of ratios			
Current assets (excluding fair value of financial derivatives)		30,517	32,190
Current liabilities (including short term debt and excluding other liability and fair value of financial derivatives)		200,411	185,051
Net debt		169,894	152,861
Total debt (bank loan)		138,248	135,682
Shareholders' equity (share capital plus retained earnings (deficit))		346,248	539,425
Total capitalization (total debt plus shareholders' equity)		484,496	675,107
Funds flow from operations [1] (year ended December 31)		98,585	100,478
Net debt/funds flow from operations	< 1.5 times	1.7	1.5
Total debt/total debt plus shareholders' 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*

18. SUPPLEMENTAL CASH FLOW INFORMATION

The net change in working capital is comprised of:

Year ended December 31	2011 $	2010 $
Source (use) of cash:		
Accounts receivable	7,570	12,441
Deposits and prepaid expenses	(5,897)	2,829
Accounts payable and accrued liabilities	12,794	(6,162)
	14,467	9,108
Related to operating activities	6,036	3,378
Related to investing activities	8,431	5,730
	14,467	9,108

19. RESTRUCTURING COSTS

In March 2010 the Board of Directors initiated a process to identify and consider strategic alternatives, with a view to enhancing shareholder value. The strategic review process was completed in July 2010. In conjunction with the sale of assets in the Puskwa area of Alberta in the second quarter of 2010, the Corporation restructured its technical and operational teams. Expenses of $1.2 million related to the restructuring process were incurred during the year ended December 31, 2010.

20. SUBSEQUENT EVENTS

Share issuance

Subsequent to December 31, 2011, the Corporation entered into an agreement with a syndicate of underwriters to issue, on a bought deal basis, 12,000,000 Class A shares at a price of $3.05 per share for aggregate proceeds, before share issue costs, of $36.6 million. Closing of the offering occurred on January 24, 2012.

Business combinations

On January 31, 2012, the Corporation purchased interests in certain natural gas properties in the Boyer area of Alberta for cash consideration of $61.5 million. At December 31, 2011, a deposit of $6.1 million paid towards the transaction is included in deposits and prepaid expenses.

The preliminary details of the transaction are as follows:

	$
Property and equipment	82,658
Decommissioning liabilities	(21,154)
Identifiable net assets acquired	61,504
Cash consideration paid	61,504

Had the transaction closed on January 1, 2011, the incremental revenue reported by the Corporation for the year ended December 31, 2011 would have been approximately $29.4 million (unaudited). The impact of this acquisition on net income, as if acquired at the beginning of the reporting period for December 31, 2011 is impracticable to determine.

On February 15, 2012, the Corporation purchased interests in certain petroleum and natural gas properties in the Peace area of Alberta for cash consideration of $6.0 million.

The preliminary details of the transaction are as follows:

	$
Property and equipment	9,086
Decommissioning liabilities	(3,044)
Identifiable net assets acquired	6,042
Cash consideration paid	6,042

The impact of this acquisition on revenue and net income, as if acquired at the beginning of the reporting period for December 31, 2011 is impracticable to determine as the historical accounting records for the acquired assets are not readily available for periods prior to the acquisition.

Financial derivative contracts

Subsequent to December 31, 2011, the Corporation entered into the following commodity financial derivative transactions:

Natural Gas:		
New contracts		
March 1, 2012 - December 31, 2012	5,000 GJ/d	CDN $4.50/GJ
March 1, 2012 – December 31, 2012	5,000 GJ/d	CDN $4.50/GJ
Crude Oil:		
Other:		
Contracts unwound		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US $85.00/Bbl Put
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $85.00/Bbl Put
Fixed Price:		
New contracts		
February 1, 2012 – February 29, 2012	1,000 Bbl/d	WTI US $91.25/Bbl
March 1, 2012 – June 30, 2012	1,000 Bbl/d	WTI CDN $91.25/Bbl
March 1, 2012 – June 30, 2012	1,100 Bbl/d	WTI US $94.00/Bbl
July 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US $91.25/Bbl Call
July 1, 2012 – December 31, 2012	1,100 Bbl/d	WTI US $94.00/Bbl Call
Costless Collar:		
January 1, 2013 – December 31, 2013	500 Bbl/d	WTI CDN $98.00-$102.00/Bbl

The new fixed price oil contracts have initial terms to June 30, 2012, at which time the counterparties may elect to extend the term of these contracts to December 31, 2012.

Also subsequent to December 31, 2011, the $50 million interest rate swap at 1.34% was unwound and a new contract was entered into with the following terms:

Notional Amount CAD $75 million Term: February 6, 2012 – January 5, 2014
Fixed rate 1.19% - Floating rate is reset monthly against CAD-BA-CDOR

Property disposition

Subsequent to December 31, 2011 the Corporation entered into an agreement to dispose of properties in the Senex area of Alberta for cash consideration of $11.0 million before closing adjustments, a 3% royalty interest, and reimbursement for the cost of a recently completed horizontal well. The transaction is expected to close on March 30, 2012.

21. RECONCILIATION OF CANADIAN GAAP FINANCIAL STATEMENTS TO IFRS

Consolidated Statement of Financial Position
As at January 1, 2010

($000s)	Canadian GAAP	Effect of transition to IFRS	IFRS Reclassifications (h)	IFRS
ASSETS				
CURRENT				
Accounts receivable	41,270	-	-	41,270
Deposits and prepaid expenses	6,190	-	-	6,190
Fair value of financial derivatives	4,241	-	-	4,241
Deferred income taxes (h)	2,884	-	(2,884)	-
	54,585	-	(2,884)	51,701
Goodwill (b)	34,891	(9,558)	-	25,333
Equipment inventory (h)	6,116	-	(6,116)	-
Property and equipment (a) (f) (h)	1,041,140	(165,319)	6,116	881,937
	1,136,732	**(174,877)**	**(2,884)**	**958,971**
LIABILITIES				
CURRENT				
Accounts payable and accrued liabilities	55,531	-	-	55,531
Financing lease	1,545	-	-	1,545
Bank loan	217,243	-	-	217,243
Other liability (d)	-	3,775	-	3,775
Fair value of financial derivatives	13,789	-	-	13,789
	288,108	3,775	-	291,883
Decommissioning liabilities (c)	41,499	(3,271)	-	38,228
Deferred income taxes (g) (h)	94,262	(42,133)	(2,884)	49,245
	423,869	(41,629)	(2,884)	379,356
SHAREHOLDERS' EQUITY				
Share capital (d)	599,334	(3,775)	-	595,559
Contributed surplus (e)	28,884	1,290	-	30,174
Retained earnings (deficit)	84,645	(130,763)	-	(46,118)
	712,863	(133,248)	-	579,615
	1,136,732	**(174,877)**	**(2,884)**	**958,971**

Reconciliation of Retained Earnings (Deficit)

($000s)	December 31, 2010	January 1, 2010
Reported under Canadian GAAP	**45,698**	**84,645**
IFRS adjustments, each net of deferred tax:		
Development and production asset impairment (a)	(122,336)	(122,336)
Goodwill impairment (b)	(9,558)	(9,558)
Decommissioning liability adjustment (c)	2,421	2,421
Share-based compensation adjustment (e)	(1,290)	(1,290)
Opening statement of financial position adjustment	**(130,763)**	**(130,763)**
Accretion expense adjustment (c)	(93)	-
Share-based compensation expense adjustment (e)	(375)	-
Depletion and depreciation expense adjustment (f)	36,202	-
Derecognition expense (f)	(6,784)	-
Other income (f)	250	-
Goodwill allocated to disposed properties (b)	4,736	-
Impairment of goodwill (b)	4,822	-
Flow-through share expense (d)	(687)	-
Tax deduction of share issue costs (g)	1,089	-
Tax rate change on opening IFRS adjustments (g)	(1,296)	-
Income statement adjustment	**37,864**	**-**
Reported under IFRS	**(47,201)**	**(46,118)**

Consolidated Statement of Financial Position
As at December 31, 2010

($000s)	Canadian GAAP	Effect of transition to IFRS: As at January 1, 2010	Effect of transition to IFRS: Year ended December 31, 2010	IFRS Reclassifications (h)	IFRS
ASSETS					
CURRENT					
Accounts receivable	28,829	-	-	-	28,829
Deposits and prepaid expenses	3,361	-	-	-	3,361
Fair value of financial derivatives	20,815	-	-	-	20,815
	53,005	-	-	-	53,005
Goodwill (b)	-	(9,558)	9,558	-	-
Equipment inventory (h)	5,876	-	-	(5,876)	-
Property and equipment (a) (f) (h)	934,494	(165,319)	41,596	5,876	816,647
	993,375	**(174,877)**	**51,154**	**-**	**869,652**
LIABILITIES					
CURRENT					
Accounts payable and accrued liabilities	49,369	-	-	-	49,369
Bank loan	135,682	-	-	-	135,682
Future income taxes (h)	3,630	-	-	(3,630)	-
Other liability (d)	-	3,775	(3,775)	-	-
Fair value of financial derivatives	6,411	-	-	-	6,411
	195,092	3,775	(3,775)	(3,630)	191,462
Decommissioning liabilities (c)	43,094	(3,271)	124	-	39,947
Fair value of financial derivatives	14,980	-	-	-	14,980
Deferred income taxes (g) (h)	70,500	(42,133)	11,260	3,630	43,257
	323,666	(41,629)	7,609	-	289,646
SHAREHOLDERS' EQUITY					
Share capital (d)	587,028	(3,775)	3,373	-	586,626
Contributed surplus (e)	36,983	1,290	2,308	-	40,581
Retained earnings (deficit)	45,698	(130,763)	37,864	-	(47,201)
	669,709	(133,248)	43,545	-	580,006
	993,375	**(174,877)**	**51,154**	**-**	**869,652**

Consolidated Statement of Earnings (Loss), and Comprehensive Income (Loss)

Year ended December 31, 2010

($000s)	Canadian GAAP	Effect of transition to IFRS	IFRS
INCOME			
Petroleum and natural gas revenue	207,831	-	207,831
Royalties, net of GCA	(31,390)	-	(31,390)
Realized gain on financial derivatives	10,552	-	10,552
Unrealized gain on financial derivatives	8,972	-	8,972
Other income (f)	-	334	334
	195,965	334	196,299
EXPENSES			
Operating	51,405	-	51,405
Transportation	8,806	-	8,806
General and administration (h)	14,773	-	14,773
Restructuring costs	1,242	-	1,242
Share-based compensation (e) (h)	4,072	375	4,447
Interest	10,086	-	10,086
Accretion (c)	2,860	124	2,984
Derecognition expense (f)	-	9,069	9,069
Depletion and depreciation (f)	128,284	(48,398)	79,886
Goodwill allocated to disposed properties (b)	4,736	(4,736)	-
Impairment of goodwill (b)	30,155	(4,822)	25,333
	256,419	(48,388)	208,031
Earnings (loss) before taxes	(60,454)	48,722	(11,732)
Income taxes			
Capital and other taxes	203	-	203
Deferred income taxes (recovery) (g)	(21,710)	10,858	(10,852)
	(21,507)	10,858	(10,649)
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**(38,947)**	**37,864**	**(1,083)**

Consolidated Statement of Cash Flows

Year ended December 31, 2010

($000s)	Canadian GAAP	Effect of transition to IFRS	IFRS
Cash provided by (used in):			
OPERATING ACTIVITIES			
Net earnings (loss)	(38,947)	37,864	(1,083)
Items not requiring cash:			
Deferred income taxes (recovery)	(21,710)	10,858	(10,852)
Impairment of goodwill	30,155	(4,822)	25,333
Goodwill allocated to disposed properties	4,736	(4,736)	-
Depletion and depreciation	128,284	(48,398)	79,886
Derecognition expense	-	9,069	9,069
Accretion	2,860	124	2,984
Share-based compensation	4,072	375	4,447
Other income	-	(334)	(334)
Unrealized gain on financial derivatives	(8,972)	-	(8,972)
Abandonment costs	(491)	-	(491)
Change in non-cash working capital	3,378	-	3,378
	103,365	-	103,365
FINANCING ACTIVITIES			
Issue of common shares	337	-	337
Repurchase of common shares	(4,154)	-	(4,154)
Financing lease payments	(1,545)	-	(1,545)
Bank loan repayment	(81,561)	-	(81,561)
	(86,923)	-	(86,923)
INVESTING ACTIVITIES			
Disposals of equipment inventory	240	(240)	-
Additions to property and equipment	(136,570)	240	(136,330)
Acquisitions of oil and gas properties	(17,791)	-	(17,791)
Disposals of oil and gas properties	131,949	-	131,949
Change in non-cash working capital	5,730	-	5,730
	(16,442)	-	(16,442)
CHANGE IN CASH	-	-	-
CASH, BEGINNING AND END OF PERIOD	-	-	-

a) IFRS 1 election for full cost oil and gas entities

The Corporation elected under IFRS 1 D8A to measure the Canadian full cost pool at the amount determined under Canadian GAAP upon transition to IFRS (the "full cost exemption"). The Canadian GAAP full cost pool was allocated to production and development assets pro-rata using proven and probable reserve values. There were no exploration and evaluation assets on January 1, 2010.

Under IFRS, the impairment test compares the carrying value of an asset to the greater of its fair value less costs to sell or its value in use. IFRS impairment calculations are done at an asset or cash-generating unit (CGU) level, compared to being calculated at the country cost centre under Canadian GAAP. CGUs are identified on the basis of cash inflows being independent from other assets or groups of assets. The impairment tests required on transition resulted in a $165.3 million ($122.3 million net of deferred tax) impairment of development and production assets.

b) Goodwill

Under IFRS, goodwill was allocated to CGU's and tested for impairment at the operating segment level, compared to an impairment calculation at the reporting unit under Canadian GAAP. This change resulted in a $9.6 million write-down of goodwill upon transition to IFRS, and a reversal of the $4.7 million allocation of goodwill to disposed properties under Canadian GAAP during the year ended December 31, 2010.

At December 31, 2010, goodwill was considered impaired in both the Canadian GAAP and IFRS financial statements. The IFRS impairment was $4.8 million lower than the Canadian GAAP impairment due to the impairment taken on transition to IFRS, less the allocation of goodwill to disposed properties which was not applicable under IFRS.

c) Decommissioning liabilities

Under Canadian GAAP decommissioning liabilities were discounted at an average historical credit adjusted risk free rate of 7.4%. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been discounted at the January 1, 2010 credit adjusted risk free rate of 8%. As a result of the full cost election for oil and gas entities described above, this resulted in a $3.3 million decrease in the decommissioning liability, with a corresponding increase in retained earnings ($2.4 million net of deferred tax) on transition.

As a result of the change in the decommissioning obligation, accretion expense increased by $124,000 ($93,000 net of deferred tax) during the year ended December 31, 2010, under IFRS compared to Canadian GAAP.

d) Flow-through shares

The Corporation has financed 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. Under Canadian GAAP, to recognize the foregone tax benefits to the Corporation, the carrying value of the shares issued is reduced by the tax effect of the tax benefits renounced to subscribers when the renouncements are filed.

Under IFRS, share capital is recorded at the fair value of the shares issued, excluding any premium received for the tax benefits to be renounced. The difference between the premium received and the liability for the tax benefits renounced is recorded as tax expense in the statement of earnings when the expenditures are incurred and the renouncement has been filed. Upon transition to IFRS,

this resulted in a decrease to share capital of $3.8 million, and the establishment of a $3.8 million other liability.

The $4.5 million future tax liability and corresponding reduction to share capital booked under Canadian GAAP in 2010 when the flow–through renouncements were filed was reversed under IFRS. Under IFRS, a deferred tax liability of $4.5 million, including a deferred tax expense of $0.7 million, was recorded during the year ended December 31, 2010.

e) Share-based compensation

Under Canadian GAAP, the Corporation recognized an expense related to share-based compensation on a straight-line basis over the vesting period, and the expense did not incorporate an estimated forfeiture rate. Under IFRS, the Corporation is required to estimate a forfeiture rate and to recognize share-based compensation over the individual vesting periods for graded vesting awards. Upon transition to IFRS, this resulted in a $1.3 million increase to contributed surplus with a corresponding decrease in retained earnings.

As a result of the change in the share-based compensation methodology, share-based compensation increased by $2.3 million during the year ended December 31, 2010 under IFRS compared to Canadian GAAP.

Under Canadian GAAP the Corporation did not capitalize share-based compensation expense as the amount was not considered material. Under IFRS the Corporation capitalized $1.9 million in share-based compensation expense during the year ended December 31, 2010. There was no impact of this change to property and equipment at transition due to the full cost election described above.

f) Property and equipment

The impact of the IFRS adjustments on property and equipment is summarized as follows:

($000s)	**Year ended December 31, 2010**	**As at January 1, 2010**
Impairment (a)	-	(165,319)
Reduction in depletion expense	48,398	-
Derecognition expense	(9,069)	-
Capitalization of share-based compensation (e)	1,933	-
Other income	334	-
Current period statement of financial position adjustment	**41,596**	**(165,319)**

Upon transition to IFRS, the Corporation adopted a policy of depleting oil and natural gas interests on a unit of production basis using estimated proven plus probable reserves. The depletion policy under Canadian GAAP was based on units of production using estimated proven reserves. In addition, depletion was calculated for the Canadian cost centre under Canadian GAAP. IFRS requires items of property and equipment with significant costs to be depleted and depreciated separately.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election for full cost oil and gas entities discussed above.

During the year ended December 31, 2010 depleting property and equipment using proven and probable reserves resulted in a decrease to depletion and depreciation expense under IFRS

compared to Canadian GAAP of $48.4 million ($36.2 million net of deferred tax) with a corresponding change to property and equipment.

Under IFRS, the carrying amount of an item of property and equipment is derecognized on disposal, or when future economic benefits are no longer expected from its use or disposal. As a result, $9.1 million in costs ($6.8 million net of deferred tax) associated with expiring lands were expensed during the year ended December 31, 2010.

Non-monetary transactions for the acquisition or disposal of property and equipment are measured at fair value under IFRS. During the year ended December 31, 2010, other income of $0.3 million ($0.3 million net of deferred tax) was recognized relating to farm-out arrangements, with a corresponding change to property and equipment.

g) *Deferred income taxes*

Under IFRS, 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. Accordingly, during the year ended December 31, 2010, $1.1 million of deferred tax expense relating to the deduction of share issue costs has been reclassified from deferred tax expense under Canadian GAAP to share capital.

The impact of the IFRS adjustments on deferred taxes is summarized as follows:

($000s)	**December 31, 2010**	**January 1, 2010**
Current deferred income tax asset	-	(2,884)
Current deferred income tax liability	3,630	-
Long-term deferred income tax liabilty	70,500	94,262
Reported under Canadian GAAP	**74,130**	**91,378**
IFRS adjustments:		
Property and equipment impairment (a)	(42,983)	(42,983)
Decommissioning liability adjustment (c)	850	850
Opening statement of financial position adjustment	**(42,133)**	**(42,133)**
Accretion expense adjustment (c)	(31)	-
Depletion and depreciation expense (f)	12,196	-
Derecognition expense (f)	(2,285)	-
Other income (f)	84	-
Tax deduction of share issue costs	(1,089)	-
Flow-through share expense (d)	687	-
Tax rate change on opening IFRS adjustments	1,296	-
Income statement adjustment	**10,858**	**-**
Flow-through share renouncement (d)	(4,462)	-
Flow-through share expenditures (d)	3,775	-
Tax deduction of share issue costs (d)	1,089	-
Current period statement of financial position adjustment	**11,260**	**-**
Reported under IFRS	**43,257**	**49,245**

h) IFRS reclassifications

Under IFRS, deferred taxes are presented as non-current and equipment inventory is presented as property and equipment.

i) IFRS exemptions

In addition to the IFRS 1 full cost exemption discussed above, the Corporation elected to apply IFRS 3 *Business Combinations* prospectively and not restate business combinations that occurred prior to January 1, 2010. The Corporation also elected to not apply IFRS 2 *Share-Based Payments* to equity awards that vested prior to January 1, 2010.