

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

<i>(\$000s except per share and per unit amounts)</i>	2011	2010	2009³
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	\$/BOE	5,401,855 BOE	\$/BOE
(\$000s)				
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 operations²	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 (\$000s)	2011		2010	
		%		%
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:		
<hr/>		
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
<hr/>		
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	(\$000s)	\$/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.

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 operations²	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 operations²	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.