SONDE RESOURCES CORP.
Form 6-K
August 12, 2011

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer
Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934

For the month of, August 2011

Commission File Number 001-31395

Sonde Resources Corp.
(Translation of registrant's name into English)

Suite 3200, 500 - 4th Avenue SW, Calgary, Alberta, Canada T2P 2V6
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40F:

Form 20-F	Form 40-F	X

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7):

Indicate by check mark whether by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No X

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_______________

DOCUMENTS INCLUDED AS PART OF THIS REPORT

Document	Description
1.	Interim Financial Statements for the three months ended June 30, 2011.
2.	Management's Discussion and Analysis for the three months ended June 30, 2011.
3.	Canadian Form 52-109F2 Certification of Interim Filings – CEO.
4.	Canadian Form 52-109F2 Certification of Interim Filings – CFO.

This Report on Form 6-K is incorporated by reference into the Registration Statement on Form F-3 of the Registrant, which was originally filed with the Securities and Exchange Commission on April 21, 2010 (File No. 333-166209).

Document 1

SONDE RESOURCES CORP.
CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(unaudited)

(CDN$ thousands)	June 30 2011	December 31 2010	January 1 2010 (Restated - note 5e)
Assets (note 11)			
Current			
Cash and cash equivalents(note 16)	40,837	2,649	3,305
Restricted cash (note 6a)	19,290	--	1,364
Accounts receivable	5,934	7,147	11,340
Derivative financial assets (note 8)	410	--	--
Prepaid expenses and deposits	1,344	1,686	3,185
Assets of discontinued operations (note 6)	40	100,692	23,819
	67,855	112,174	43,013
Long term portion of prepaid expenses and deposits	470	555	878
Exploration and evaluation assets (note 7)	62,242	49,361	12,526
Property, plant and equipment, net (note 7)	104,645	102,603	145,678
Assets of discontinued operations (note 6)	--	--	88,972
	235,212	264,693	291,067
Liabilities			
Current			
Accounts payable and accrued liabilities	14,978	18,126	26,443
Stock based compensation liability (note 15)	1,884	530	55
Provisions (note 10)	12,086	12,692	1,146
Derivative financial liabilities (note 8)	3,452	5,099	--
Short term debt (note 11)	21,365	35,048	39,368
Liabilities of discontinued operations (note 6)	1,170	16,650	1,793
	54,935	88,145	68,805
Decommissioning provision	18,841	18,197	15,905
Liabilities of discontinued operations (note 6)	--	--	2,763
	73,776	106,342	87,473
Contingencies and commitments (note 17)			
Shareholders' Equity			
Share capital	369,892	369,892	311,270
Warrants	--	--	76
Contributed surplus	33,514	31,068	28,494
Foreign currency translation reserve	(1,670)	(5,789)	--
Deficit	(240,300)	(236,820)	(136,246)
	161,436	158,351	203,594
	235,212	264,693	291,067

See accompanying notes to the unaudited condensed consolidated financial statements

On behalf of the Board,

(Signed) “Jack Schanck” (Signed) “W. Gordon Lancaster”

Jack Schanck	W. Gordon Lancaster
Director and Chief Executive Officer	Director

SONDE RESOURCES CORP.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS & COMPREHENSIVE INCOME (LOSS)
(unaudited)

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
(CDN$ thousands, except per share amounts)				
Revenue				
Revenue, net of royalties (note 12)	7,894	7,092	16,826	15,760
Gain (loss) on commodity derivatives (notes 8, 9)	1,121	62	(543)	2,909
	9,015	7,154	16,283	18,669
Expenses				
Operating (note 13)	3,204	2,691	6,909	5,567
Transportation	257	333	516	610
Exploration	206	41	370	199
General and administrative	2,144	3,359	4,387	5,710
Depletion and depreciation	2,961	4,364	6,243	8,739
Stock based compensation (note 15)	1,669	561	3,799	1,053
Property, plant and equipment impairment	--	15,238	--	15,238
Bad debt	--	885	--	915
Loss on abandonment	--	7	775	7
	10,441	27,479	22,999	38,038
Operating loss	(1,426)	(20,325)	(6,716)	(19,369)
Other				
Financing costs (note 14)	(802)	(507)	(1,453)	(1,007)
Loss on foreign exchange	(1,020)	(847)	(548)	(188)
Gain (loss) on financial derivatives	2,255	1,939	2,633	(1,779)
Other income	3	169	59	280
Loss on exchange of preferred shares	--	--	--	(172)
	436	754	691	(2,866)
Loss before income taxes from continuing operations	(990)	(19,571)	(6,025)	(22,235)
Current income taxes	120	386	120	386
Loss from continuing operations	(1,110)	(19,957)	(6,145)	(22,621)
Income (loss) from discontinued operations, net tax (note 6)	3,891	(31)	2,665	(64)
Net income (loss)	2,781	(19,988)	(3,480)	(22,685)
Other comprehensive loss				
Foreign currency translation adjustment	(201)	8	(1,118)	(44)
Foreign currency translation adjustment relating to assets and liabilities of discontinued operations (note 6)	550	5,693	(1,128)	2,146
Foreign currency translation reclassified to net earnings (note 6)	6,365	--	6,365	--
Other comprehensive income (loss)	6,714	5,701	4,119	2,102
Total comprehensive income (loss)	9,495	(14,287)	639	(20,583)
Net loss per common share				
Basic and diluted loss per common share from continuing operations	$(0.02)	$(0.33)	$(0.10)	(0.38)

Basic and diluted income per common share from discontinued operations	$0.06	--	$0.04	--
	$0.04	$(0.33)	$(0.06)	(0.38)

See accompanying notes to the unaudited condensed consolidated financial statements

SONDE RESOURCES CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
(CDN$ thousands)				
Cash provided by (used in):				
Operating				
Net income (loss)	2,781	(19,988)	(3,480)	(22,685)
Items not involving cash:				
Depletion and depreciation	2,961	4,364	6,243	8,739
Stock based compensation	1,669	561	3,799	1,053
Property, plant and equipment impairment	--	15,238	--	15,238
Unrealized (gain) loss on commodity derivatives	(1,011)	861	729	(1,776)
Unrealized (gain) loss on financial derivatives	(2,255)	(1,938)	(2,633)	1,779
Unrealized (gain) loss on foreign exchange	712	1,424	1,314	768
Financing costs	1,103	538	1,946	1,071
Loss on abandonment	--	7	775	7
Loss on exchange of preferred shares	--	--	--	172
Gain on disposition of discontinued operations	(4,600)	--	(4,600)	--
Interest paid	(937)	(305)	(1,584)	(551)
Decommissioning expenditures	--	(35)	(846)	(35)
	423	727	1,663	3,780
Changes in non-cash working capital (note 16)	1,654	703	1,089	(4,985)
	2,077	1,430	2,752	(1,205)
Financing				
Revolving credit facility repayments	(15,126)	--	(34,562)	(23,987)
Revolving credit facility advances	7,793	--	14,441	--
Demand loan advances	--	--	6,902	--
Issue of common shares, net of share issue costs	--	(205)	--	58,597
	(7,333)	(205)	(13,219)	34,610
Investing				
Capital and exploration expenditures	(10,576)	(8,714)	(22,898)	(17,357)
Proceeds on disposition (note 6)	68,611	--	88,210	--
Change in non-cash working capital (note 16)	(12,616)	(6,364)	(15,724)	(10,740)
	45,419	(15,078)	49,588	(28,097)
Increase (decrease) in cash and cash equivalents	40,163	(13,853)	39,121	5,308
Cash and cash equivalents, beginning of period	1,579	22,444	2,649	3,305
Effect of foreign exchange on cash and cash equivalents	(905)	34	(933)	12
Cash and cash equivalents, end of period	40,837	8,625	40,837	8,625

See accompanying notes to the unaudited condensed consolidated financial statements

SONDE RESOURCES CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(unaudited)

(CDN$ thousands)	Share capital	Contributed surplus	Warrants	Foreign currency translation	Deficit	Total
At January 1, 2010 (Restated - note 5)	311,270	28,494	76	--	(136,246)	203,594
Total comprehensive loss	--	--	--	2,102	(22,685)	(20,583)
Issue of common shares, net of share issue costs	58,597	--	--	--	--	58,597
Warrant expiry	--	28	(28)	--	--	--
Stock based compensation expense	--	900	--	--	--	900
June 30, 2010	369,867	29,422	48	2,102	(158,931)	242,508
At December 31, 2010	369,892	31,068	--	(5,789)	(236,820)	158,351
Total comprehensive income	--	--	--	(2,246)	2,885	639
Foreign currency translation reclassified to net earnings	--	--	--	6,365	(6,365)	--
Equity based stock compensation expense (note 15)	--	2,446	--	--	--	2,446
June 30, 2011	369,892	33,514	--	(1,670)	(240,300)	161,436

See accompanying notes to the unaudited condensed consolidated financial statements

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2011
(unaudited)
(All tabular amounts in CDN$ thousands, except where otherwise noted)

1. Reporting entity

Sonde Resources Corp. (“Sonde Resources” or the “Company”) is a Canadian based energy company with its registered office located at suite 3200, 500 – 4th Avenue S.W., Calgary, Alberta. The Company is engaged in the exploration for and production of oil and natural gas. The Company’s operations are located in Western Canada and offshore North Africa. On June 22, 2011 the Company completed the sale of its offshore operations in the Republic of Trinidad and Tobago (“Trinidad and Tobago”). These condensed consolidated financial statements comprise the Company and its wholly owned subsidiaries which include Seeker Petroleum Ltd., Sonde Resources Trinidad and Tobago Ltd. and Challenger Energy Corp. The Company’s shares are publicly traded on both the Toronto Stock Exchange and the American Stock Exchange.

2. Basis of preparation

(a) Statement of compliance

In conjunction with the Company’s annual audited consolidated financial statements to be issued under International Financial Reporting Standards as issued by the International Accounting Standards Board (“IFRS”) for the year ended December 31, 2011 these interim condensed consolidated financial statements present the Company’s financial results of operations and financial position under IFRS at and for the three and six months ended June 30, 2011, including 2010 comparative periods. As a result, these condensed consolidated financial statements have been prepared in accordance with IFRS 1, First-time Adoption of International Financial Reporting Standards (IFRS 1), and with International Accounting Standard 34, Interim Financial Reporting, using the accounting policies the Company expects to adopt in its consolidated financial statements for the year ending December 31, 2011. They are condensed as they do not include all of the necessary annual disclosures required for full annual financial statements under IFRS.

In previous years, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Canadian GAAP). Comparative information has been restated from Canadian GAAP to IFRS. The impact of the transition to IFRS on the Company’s previously reported financial statements is presented in Note 5.

These unaudited interim condensed consolidated financial statements have been prepared in accordance with those IFRS standards and International Financial Reporting Interpretations Committee (“IFRIC”) interpretations required to be applied for annual periods beginning on or after January 1, 2011 which were issued and effective as of the date of approval by the Company’s Board of Directors of these interim financial statements. The IFRS standards and IFRIC interpretations that will be applicable at December 31, 2011, including those that will be applicable on an optional basis, are not known with certainty at the time of preparing these unaudited interim condensed consolidated financial statements. Accordingly, the accounting policies for the annual period that are relevant to these unaudited interim condensed consolidated financial statements will be determined only when the first annual IFRS financial statements are prepared for the year ending December 31, 2011. The statements were approved and authorized for issue by the Board of Directors on August 11, 2011 and should be read in conjunction with the Audited Consolidated Financial Statements for the year ended December 31, 2010, which have been prepared in accordance with Canadian GAAP.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except as detailed in the Company's accounting policies disclosed in Note 3. The accounting policies described in Note 3 have been applied consistently to all periods presented in these financial statements except for the opening IFRS consolidated statement of financial position, which has utilized optional exemptions available and mandatory exemptions under IFRS 1 as described in Note 5.

On June 3, 2010, the Company's shareholders approved the consolidation of the Company's outstanding shares on a five for one basis effective on the close of business June 4, 2010. The effect of the consolidation was to reduce to one-fifth the number of common shares, warrants, stock options and stock unit awards outstanding. The number of shares into which the preferred shares are convertible were also reduced to one-fifth. In addition, the conversion price of the preferred shares, the weighted average exercise price and fair value per options, warrants and stock unit awards have been adjusted to five times the pre-consolidation prices. All share and per share amounts included in these financial statements have been adjusted retroactively for the consolidation.

2. Basis of preparation (continued)

These consolidated financial statements have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business

(c) Functional and reporting currencies

These consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgment

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant accounting estimates and judgments used in the preparation of the financial statements are described in Note 4.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

(a) Principles of consolidation

The Company consolidates its interest in entities in which it controls. Control comprises the power to govern an entity's financial and operating policies so as to obtain benefits from its activities. The Company recognizes its proportionate share of assets, liabilities, income and expenses, on a line-by-line basis, of its jointly controlled assets. All material intercompany balances and transactions have been eliminated.

(b) Cash and cash equivalents

Cash and cash equivalents consist of balances with banks and investments in highly liquid short-term deposits with minimal principal risk.

(c) Foreign currency

Functional currencies of each of the Company's foreign operations represent the currency of the primary economic environment in which it operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the statement of financial position date. Foreign exchange differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the Company's condensed consolidated financial statements, the financial statements of each entity are translated into Canadian dollars, the Company's reporting currency. The assets and liabilities of foreign operations are translated into Canadian dollars using foreign exchange rates at the statement of financial position date.

Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in other comprehensive income.

If the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are reclassified to net income or loss.

3. Significant accounting policies (continued)

(d) Exploration and evaluation assets and property, plant and equipment

(i) Recognition and measurement

Costs of exploring for and evaluating oil and natural gas properties are initially capitalized within exploration and evaluation assets. Such exploration and evaluation costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses and the projected costs of retiring the assets (if any), but do not include exploration or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are expensed directly to net income or loss as they are incurred.

Exploration and evaluation assets are not amortized, but are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying value exceeds the recoverable amount. These assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the assets may be transferred to intangible assets when it meets the recognition criteria for intangible assets. Not proceeding with development of the asset is an impairment indicator, and as a result of the decision impairment testing would be performed.

When management determines with reasonable certainty that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is first tested for impairment and then reclassified to property, plant and equipment.

Items of property, plant and equipment are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items.

The costs to acquire developed or producing oil and gas properties and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install dedicated infrastructure such as wellhead equipment and supporting assets, are capitalized as oil and gas properties within property plant and equipment.

The costs of major inspection, overhaul and work-over activities that maintain property, plant and equipment and benefit future years of operations are capitalized. Similar recurring planned maintenance managed on shorter intervals is expensed. Replacements outside major inspection, overhaul or work-overs are capitalized when it is probable that future economic benefits will flow to the Company and the associated carrying value of the replaced asset is derecognized.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, and intangible exploration assets, are determined by comparing the proceeds from disposal with its carrying value and are recognized within "other income" or "other expenses" in net income or loss.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in net income or loss using the effective interest method. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for it to be capable of operating as intended. Capitalization of borrowing costs is suspended when the construction of an asset is ceased for extended periods.

The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the year, including the dividends on the convertible preferred shares.

3. Significant accounting policies (continued)

(ii) Depletion and depreciation

The carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves.

Proved and probable reserves are estimated annually by independent reserve engineers and 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 producible. There should be a more than 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable. The equivalent statistical probability for the proved component is 90%.

Such reserves may be considered economically 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;
- evidence that necessary production, transmission and transportation facilities are available or can be made available; and
- availability of capital to develop reserves.

Reserves may only be considered proved and probable if supported by either actual production or a conclusive formation test. The area of reservoir considered proved 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 proved limit of the reservoir.

Reserves which can be produced economically through application of unproved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successfully tested by a pilot project, the operation of an installed program in the reservoir or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

For other assets, depreciation is recognized in net income or loss on a declining balance basis over its estimated useful life at rates varying from 20% to 100%. Land is not depreciated.

Depreciation methods, useful lives and residual values are reviewed annually.

(e) Leased assets

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to the asset. The Company does not have any financing leases.

Other leases are operating leases, which are not recognized on the Company's statement of financial position.

Payments made under operating leases are recognized in net income or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

3. Significant accounting policies (continued)

(f) Impairment

(i) Non-financial assets

The carrying value of the Company's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment and also if facts and circumstances suggest that the carrying value exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

In assessing fair value less cost to sell, the fair value reflects the price a market participant would be willing to pay to acquire the asset or CGU less selling costs to complete the transaction. Fair value is generally determined based on recent transactions, crown land sales and other market metrics.

Exploration and evaluation assets are allocated to the CGUs on a geographical basis when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and natural gas interests in property, plant and equipment.

An impairment loss is recognized if the carrying value of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income or loss. Impairment losses recognized in respect of CGUs reduce the carrying value of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss recognized in prior years is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying value does not exceed the carrying value that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(ii) Financial assets

A financial asset, other than a financial asset designated as fair value through profit and loss, is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying value, and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized and is recognized in net income or loss.

3. Significant accounting policies (continued)

(g) Financial instruments

Financial assets and liabilities designated as fair value through profit or loss are measured at fair value with changes in those fair values recognized in the statement of operations. Financial assets available for sale are measured at fair value, with changes in those fair values recognized in other comprehensive income. Financial assets held to maturity, loans and other receivables and other financial liabilities are measured at amortized cost using the effective interest method.

Derivatives are classified as fair value through profit or loss and measured at their fair value. Gains or losses related to periodic revaluation are recorded to the statement of operations.

Fair value measurements are classified according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1: Quoted prices are available in active markets. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Pricing inputs are other than quoted prices in an active market included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

Level 3: Valuations are derived from valuation techniques in which on more significant inputs are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

(h) Share based compensation

(i) Stock option awards

Stock based compensation expense is recorded in net income or loss for all options granted on a graded basis over the vesting period of the option. The Company has both equity and liability based stock option plans. For the equity based stock option plan grant awards are satisfied upon exercise with the issuance of common shares. Increases in equity based stock option expense are recorded as contributed surplus. Compensation expense for this plan is based on the estimated fair values of the options at the time of the grant as determined using a Black-Scholes option pricing model. The Company incorporates an estimated forfeiture rate when determining compensation expense for stock options that will not vest. Upon the exercise of the equity based stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase in share capital. In the event that vested options expire, previously recognized compensation expense associated with such stock options is not reversed.

The liability based stock option plan satisfies grant awards upon exercise with cash. Increases in the liability-based stock option expense are recorded as stock based compensation liability. Compensation expense for this plan is based on the estimated fair values of the options at the time of the grant as determined using a Black-Scholes option pricing model, revalued at each reporting date using updated inputs to reflect the fair value of the liability. The Company incorporates an estimated forfeiture rate when determining compensation expense for stock options that will not vest. Upon the exercise of the liability based stock options, cash distributions will be reflected as reduction of stock based compensation liability, factored into revaluation at subsequent reporting periods. In the event that vested options expire, previously recognized compensation expense associated with such stock options is factored into the revaluation of the liability at subsequent reporting periods.

(ii) Stock unit awards

Stock unit awards are only payable in cash. Obligations are accrued to stock based compensation liability based on the vesting period of the stock unit awards using the fair value of the Company's common shares with the change in value charged to stock based compensation expense. The obligations are revalued each reporting period based on the change in the fair value of the Company's common shares and the number of vested stock unit awards outstanding. The Company reduces the liability when the units are surrendered for cash.

3. Significant accounting policies (continued)

(iii) Restricted share units

The Restricted Share Unit Plan became effective on March 24, 2011, to attract and retain experienced personnel with incentive compensation tied to shareholder return. Under the plan, the Board will pay on a vesting date to such grantee, in respect of each Restricted Share Unit a cash amount equal to the fair market value of one common share in the capital of the Company on such vesting date. The obligations are revalued each reporting period based on a binomial lattice approach. The assumptions included in the model include the risk-free discount rate, volatility, vesting date, and the vesting price condition. The expense charged to stock based compensation expense on a straight line basis over the vesting period for each tranche of units. The corresponding liability is accrued to stock based compensation liability.

(i) Provisions

A provision is recognized if, as a result of a past event, the Company 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. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risk specific to the liability. Provisions are not recognized for future operating losses. Further details on specific provisions are as follows:

(i) Decommissioning liabilities

The Company recognizes the estimated liability associated with decommissioning at the time the asset is acquired and the liability is incurred. The estimated present value of the future payments of the decommissioning liability is recorded as a long term liability, with a corresponding increase in the carrying value of property, plant and equipment. Amounts are discounted using the risk-free rate. The capitalized amount is depleted on a unit-of-production method over the life of proved and probable reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to net income or loss in the period. The liability can also increase or decrease due to changes in the estimates of timing of cash flows, changes to the risk-free rate or changes in the original estimated undiscounted cost. The change in the provision as a result of these changes is capitalized in the carrying value of the related asset. Actual costs incurred upon settlement of decommissioning liabilities are charged against the decommissioning liability to the extent of the liability recorded.

(ii) Onerous contracts

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligation under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net costs of continuing with the contract.

(j) Revenue

Revenue from the sale of natural gas, oil and natural gas liquids is recognized based on volumes delivered to customers at contractual delivery points and rates. Revenue is measured net of royalties.

Revenue is recognized when persuasive evidence exists that the significant risks and rewards have been transferred to the customer and the amount of revenue can be measured reliably, and when recovery of the consideration is probable. Recognition occurs upon delivery.

Tariffs and tolls charged to other entities for use of pipelines and facilities owned by the Company are recognized as revenue as they accrue in accordance with the terms of the service or tariff and tolling agreement.

Royalty income is recognized on operating lease rights as it accrues in accordance with the terms of the overriding royalty agreements.

The costs associated with the delivery, including operating and maintenance costs, transportation, and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

3. Significant accounting policies (continued)

(k) Assets of discontinued operations

Assets and liabilities are classified as held for sale if their carrying values are expected to be recovered through a disposition rather than through continuing use. After disposition, assets and liabilities related to the disposal groups are classified as assets and liabilities related to discontinued operations. The assets or disposal groups are measured at the lower of their carrying value and fair value less cost to sell. Impairment losses on initial classification as held for sale and subsequent gains or losses on re-measurement are recognized in net income or loss. Assets classified as held for sale or discontinued operations are not depreciated, depleted or amortized.

(l) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

(m) Income taxes

The Company follows the liability method of accounting for income taxes whereby deferred income taxes are recorded for unused tax losses, tax credits and the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the statement of financial position date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in income in the period which they occur. Investment tax credits are recorded as an offset to the related expenditures.

(n) Basic and diluted per share amounts

Basic per share amounts are calculated by dividing net income or loss attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share amounts are calculated by adjusting the net income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of all dilutive potential common shares, which comprise convertible preferred shares, warrants, and share options granted to employees.

(o) Convertible preferred shares

The Company’s convertible preferred shares are segregated into their debt and financial derivative components at the date of issue, based on the relative fair market value of these components in accordance with the substance of the contractual agreements. The debt component of the instrument is classified as a liability, and recorded at the present value of the Company’s obligation to make future interest payments in cash or in a variable number of shares and to settle the redemption value of the instrument in cash or at a fixed amount of approximately 33.33 common shares per one preferred share. The carrying value of the debt component is accreted to the original face value of the instruments, over their deemed life, using the effective interest method. The conversion option, which makes up the financial derivative component of the instruments, is evaluated and recorded in accordance with the Company’s accounting policy on financial instruments.

(p) Accounting standards issued but not yet applied

The Company has not applied the following new and revised IFRSs that have been issued but are not yet effective.

IFRS 7 (revised)	"Financial Instruments: Disclosures"
IFRS 9 (revised)	"Financial Instruments: Classification and Measurement"
IAS 12 (revised)	"Income Taxes"
IFRS 10 (new)	"Consolidated Financial Statements"
IFRS 11 (new)	"Joint Arrangements"
IFRS 12 (new)	"Disclosure of Interests in Other Entities"
IAS 27 (revised)	"Separate Financial Statements"
IAS 28 (revised)	"Investments in Associates and Joint Ventures"
IFRS 13 (new)	"Fair Value Measurement"
IAS 1 (revised)	"Presentation of Financial Statements"

4. Significant accounting estimates and judgments

The timely preparation of the condensed consolidated financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, those areas discussed below.

(a) Oil and gas reserves

Certain depletion, depreciation, impairment and decommissioning and restoration charges are measured based on the Company's estimate of oil and gas reserves. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. Reserves and resources have been evaluated at December 31, 2010 by independent petroleum consultants in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering dates, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at each annual reporting date, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

(b) Exploration and evaluation costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The Company is required to make estimates and judgments about the future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Unsuccessful drilling, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important factors when making this determination. If a judgment is made that the extraction of resources is not viable, the associated exploration and evaluation costs are impaired and charged to net income or loss.

(c) Decommissioning liabilities and other provisions

The Company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and prices. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented. Other provisions are recognized in the period in which it becomes probable that there will be a future cash outflow.

(d) Deferred income taxes

Deferred tax assets are recognized when it is considered probable that unused tax losses, tax credits and deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the Company's estimate, the ability of the Company to realize the deferred tax asset could be impacted.

Deferred tax liabilities are recognized for taxable temporary differences. The Company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the Company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdiction which the Company operates.

4. Significant accounting estimates and judgments (continued)

(e) Impairment of assets

The allocation of assets into cash generating units ("CGU's") requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

The recoverable amounts of CGU's and individual assets have been determined based on the higher of fair value less costs to sell. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes and future operating and development costs. Changes to these assumptions will affect the recoverable amounts of CGU's and individual assets and may then require a material adjustment to their related carrying value.

(f) Stock based compensation

Expenses recorded for stock based compensation are based on the historical volatility of the Company's share price which may not be indicative of the future volatility. Accordingly, those amounts are subject to measurement uncertainty.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS

(a) IFRS transition exemptions

IFRS 1 requires the presentation of comparative information as at the January 1, 2010 transition date and subsequent comparative periods as well as the consistent and retrospective application of IFRS accounting policies. To assist with the transition, the provisions of IFRS 1 allow for certain mandatory exceptions and optional exemptions for first-time adopters to alleviate the retrospective application of all IFRSs. The Company has applied the following exemptions to full retrospective application of IFRS in accordance with IFRS 1:

(i) Deemed cost of property plant and equipment

The Company has elected to apply the exemption under IFRS 1 allowing the measurement of oil and gas assets at the date of transition to IFRS to be determined based on the amounts disclosed under the full cost method of accounting in accordance with Canadian GAAP.

(ii) Decommissioning liabilities

The exemption provided in IFRS 1 from the full retrospective application of IFRS 1 has been applied and the difference between the carrying values of the Company's decommissioning liabilities as measured under IFRS and their carrying values under Canadian GAAP as of January 1, 2010 has been recognized directly in opening deficit.

(iii) Share-based payments

The Company has elected not to apply IFRS 2, Share-based Payments to equity instruments granted after November 7, 2002 that have not vested by the transition date.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(iv) Borrowing costs

The Company has applied the borrowing cost exemption in IFRS 1. It has applied the requirement of IAS 23 to borrowing costs relating to qualifying assets on a prospective basis from the date of transition to IFRS.

(v) Foreign currency translation

The cumulative translation differences for all foreign operations are deemed to be zero at the date of transition to IFRS. Cumulative translation differences are recorded prospectively from this date.

(vi) Business combinations

IFRS 1 allows an entity to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations.

(b) Mandatory exceptions to retrospective application

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Company under Canadian GAAP are consistent with their application under IFRS.

The remaining IFRS 1 exemptions were not applicable or material to the preparation of the Company’s Consolidated Statement of Financial Position at the date of transition on January 1, 2010.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(c) Reconciliation of assets, liabilities and shareholders' equity

The following reconciliations present the adjustments made to the Company's Canadian GAAP financial results of operations and financial position to comply with IFRS. A summary of the significant accounting policy changes and applicable exemptions are discussed following the reconciliations.

		December 31, 2010			June 30, 2010			January 1, 2010 (Restated – note xiii)		
	Note 5(e)	Canadian GAAP	Adj	IFRS	Canadian GAAP	Adj	IFRS	Canadian GAAP	Adj	IFRS
Assets										
Current										
Cash and cash equivalents		2,649	--	2,649	8,626	--	8,626	3,305	--	3,305
Restricted cash		--	--	--	1,360	--	1,360	1,364	--	1,364
Accounts receivable		7,147	--	7,147	12,940	--	12,940	11,340	--	11,340
Derivative financial assets		--	--	--	1,776	--	1,776	--	--	--
Prepaid expenses and deposits		1,686	--	1,686	5,646	--	5,646	3,185	--	3,185
Assets of discontinued operations	(i)	104,299	(3,607)	100,692	23,341	--	23,341	23,819	--	23,819
		115,781	(3,607)	112,174	53,689	--	53,689	43,013	--	43,013
Long term portion of prepaid expenses and deposits		555	--	555	665	--	665	878	--	878
Exploration and evaluation assets	(vi),(v), (viii),(xi)	--	49,361	49,361	--	15,491	15,491	--	12,526	12,526
Property, plant and equipment, net	(ii),(v)-(viii)	152,085	(49,482)	102,603	144,504	(14,917)	129,587	158,204	(12,526)	145,678
Assets of discontinued operations	(i)	--	--	--	97,644	825	98,469	89,737	(765)	88,972
		268,421	(3,728)	264,693	296,502	1,399	297,901	291,832	(765)	291,067
Liabilities										
Current										
Accounts payable and accrued liabilities		18,126	--	18,126	11,482	--	11,482	26,443	--	26,443
Stock based compensation		530	--	530	207	--	207	55	--	55

liability										
Provisions	(ix)	12,433	259	12,692	--	701	701	--	1,146	1,146
Derivative financial liabilities	(iii),(iv)	--	5,099	5,099	--	--	--	--	--	
Short term debt	(iii)	35,048	--	35,048	80	--	80	24,067	15,301	39,368
Liabilities of discontinued operations	(i)	15,212	1,438	16,650	4,462	--	4,462	1,793	--	1,793
		81,349	6,796	88,145	16,231	701	16,932	52,358	16,447	68,805
Derivative financial liabilities	(iii),(iv)	--	--	--	--	1,778	1,778	--	--	--
Convertible preferred shares	(iii)	--	--	--	15,771	--	15,771	15,301	(15,301)	--
Decommissioning provision	(ii)	13,802	4,395	18,197	13,468	4,146	17,614	12,591	3,314	15,905
Liabilities of discontinued operations	(i)	--	--	--	1,446	1,852	3,298	1,387	1,376	2,763
		95,151	11,191	106,342	46,916	8,477	55,393	81,637	5,836	87,473
Shareholder’s equity										
Share capital	(xii)	339,183	30,709	369,892	339,158	30,709	369,867	280,561	30,709	311,270
Equity portion of preferred shares	(iii)	12,682	(12,682)	--	12,682	(12,682)	--	1,969	(1,969)	--
Warrants	(iv)	303	(303)	--	351	(303)	48	76	--	76
Contributed surplus	(x)	29,452	1,616	31,068	27,572	1,850	29,422	26,923	1,571	28,494
Foreign currency translation reserve	(xi)	--	(5,789)	(5,789)	--	2,102	2,102	--	--	--
Deficit	all	(208,350)	(28,470)	(236,820)	(130,177)	(28,754)	(158,931)	(99,334)	(36,912)	(136,246)
		173,270	(14,919)	158,351	249,586	(7,078)	242,508	210,195	(6,601)	203,594
		268,421	(3,728)	264,693	296,502	1,399	297,901	291,832	(765)	291,067

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(d) Reconciliation of total comprehensive loss

		Year ended December 31, 2010 (Restated – note xiii)			Six months ended June 30, 2010			Three months ended June 30, 2010		
	Note 5(e)	Canadian GAAP	Adj	IFRS	Canadian GAAP	Adj	IFRS	Canadian GAAP	Adj	IFRS
Revenue										
Petroleum and natural gas sales, net of royalties		32,239	--	32,239	15,760	--	15,760	7,092	--	7,092
Gain on commodity derivatives		3,197	--	3,197	2,909	--	2,909	62	--	62
		35,436	--	35,436	18,669	--	18,669	7,154	--	7,154
Expenses										
Operating		13,036	--	13,036	5,567	--	5,567	2,691	--	2,691
Transportation		1,304	--	1,304	610	--	610	333	--	333
Exploration	(viii)	--	9,114	9,114	--	199	199	--	41	41
General and administrative	(ix)	12,014	(888)	11,126	6,155	(445)	5,710	3,582	(223)	3,359
Depletion and depreciation	(vii)	27,743	(11,069)	16,674	14,370	(5,631)	8,739	7,342	(2,978)	4,364
Impairments	(vi)	38,756	2,017	40,773	9,712	5,526	15,238	9,712	5,526	15,238
Stock based compensation	(x)	2,960	45	3,005	774	279	1,053	451	110	561
Bad debt		852	--	852	915	--	915	885	--	885
Loss on abandonment		123	--	123	7	--	7	7	--	7
		96,788	(781)	96,007	38,110	(72)	38,038	25,003	2,476	27,479
Operating income (loss)		(61,352)	781	(60,571)	(19,441)	72	(19,369)	(17,849)	(2,476)	(20,325)
Other										
Financing costs	(ii)	(1,239)	(664)	(1,903)	(585)	(422)	(1,007)	(302)	(205)	(507)
Gain (loss) on foreign exchange	(xi)	744	144	888	1,182	(1,370)	(188)	2,008	(2,855)	(847)
Gain (loss) on financial derivatives	(iii) (iv)	--	(5,210)	(5,210)	--	(1,779)	(1,779)	--	1,939	1,939
Other income	(viii)	165	136	301	144	136	280	105	64	169
Loss on exchange of preferred shares		(172)	--	(172)	(172)	--	(172)	--	--	--
		(502)	(5,594)	(6,096)	569	(3,435)	(2.866)	1,811	(1,057)	754
		(61,854)	(4,813)	(66,667)	(18,872)	(3,363)	(22,235)	(16,038)	(3,533)	(19,571)

Loss before income taxes from continuing operations										
Part VI.1 tax on preferred share dividends		470	--	470	386	--	386	386	--	386
Net loss from continuing operations		(62,324)	(4,813)	(67,137)	(19,258)	(3,363)	(22,621)	(16,424)	(3,533)	(19,957)
Net income (loss) from discontinued operations	(i)	(35,676)	2,238	(33,438)	(569)	505	(64)	(1,239)	1,208	(31)
Net loss		(98,000)	(2,575)	(100,575)	(19,827)	(2,858)	(22,685)	(17,663)	(2,325)	(19,988)
Other comprehensive loss										
Foreign currency translation adjustment	(xi)	--	(552)	(552)	--	(44)	(44)	--	8	8
Foreign currency translation adjustment relating to assets and liabilities held for sale	(xi)	--	(5,237)	(5,237)	--	2,146	2,146	--	5,693	5,693
Other comprehensive loss		--	(5,789)	(5,789)	--	2,102	2,102	--	5,701	5,701
Total comprehensive loss		(98,000)	(8,364)	(106,364)	(19,827)	(756)	(20,583)	(17,663)	3,376	(14,287)

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(e) Explanation of significant adjustments

(i) Assets/liabilities held for sale and discontinued operations

Foreign currency translation differences associated with the LNG Project and Trinidad and Tobago assets and liabilities were recorded as part of net loss from discontinued operations under Canadian GAAP. Under IFRS, these differences were reclassified to other comprehensive loss. See section (xi) for details on foreign currency translation differences.

Decommissioning provision differences between IFRS and Canadian GAAP associated with Trinidad and Tobago assets were recorded as changes to liabilities held for sale. The impact of changes to the accretion of these provisions was recorded to net loss from discontinued operations. See section (ii) for details on decommissioning provision differences.

(ii) Decommissioning provision

Under Canadian GAAP, increases in the estimated cash flows were discounted using the current credit-adjusted risk-free rate while downward revisions in the estimated cash flows were discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. Under IFRS, estimated cash flows are discounted using the risk-free rate that exists at the date of the statement of financial position.

In accordance with IFRS 1, the Company elected to re-measure its decommissioning provision at the IFRS transition date and has estimated the related asset by discounting the liability to the date in which the liability arose and recalculated the accumulated depreciation and depletion under IFRS. Adjustments at the IFRS transition date have been recorded to opening deficit. Adjustments arising as a result of changes in the interest rate during the 2010 period have been recorded to property plant, and equipment. The impact of these changes on accretion has been reflected as a change in financing costs.

(iii) Convertible preferred shares

Under Canadian GAAP, the convertible instrument is split into a liability and an equity component. The value of the liability component was determined at the time of placement of the instrument based on the fair value of the debt component of the instrument. The remaining amount was recorded in equity under Canadian GAAP.

The treatment of the liability component determined at the time of placement under IFRS is similar to Canadian GAAP. The initial recognition is at fair value. Under Canadian GAAP the carrying value of the liability component is subsequently accreted to its face value using the effective interest method which is similar to IFRS. No adjustment was required upon adoption of IFRS.

There is no equity instrument recorded for the conversion feature under IFRS. IFRS requires a fixed number of the Company's own equity instruments to be delivered in exchange for a fixed amount of cash to make recognition as equity possible. As the liability is denominated in United States dollars ("U.S. dollars" or "US$"), and therefore is variable in Canadian dollars, this requirement is not met for the conversion feature of the preferred shares. As a result, under IFRS no equity component can be recorded and the conversion feature is considered an embedded derivative. The embedded derivative is separated and recorded at fair value as a financial derivative liability, with changes in fair value charged to net income or loss.

On December 17, 2009, the Company renegotiated the terms of the convertible preferred shares. Pursuant to the terms of the restructuring, the Series A convertible preferred shares were exchanged for Series B convertible preferred shares and common share purchase warrants. Series A and B shares have different conversion prices and different redemption/retraction dates. The Certificate of Amendment which created the Series B shares was amended February 3, 2010. Under Canadian GAAP, the modification resulted in the Series A shares being presented as non-current at December 31, 2009, despite the redemption/retraction date of the Series A shares being December 31, 2010. Under Canadian GAAP, short term debt that is refinanced with long term debt prior to completion of the statement of financial position can be classified as non-current if certain criteria have been met. Under IFRS the appropriate treatment is to reflect the Series A shares as current liabilities in the IFRS opening statement of financial position.

The equity treatment of the modification under Canadian GAAP resulted in adjustments to contributed surplus and incremental equity on preferred shares. Under IFRS, these adjustments are reversed as the conversion features of the modified convertible preferred shares are recorded at their fair value.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(iv) Preferred share warrants

As part of the February 3, 2010 modification of the convertible preferred shares, the Company issued warrants, the exercise price of which is denominated in U.S. dollars. Under Canadian GAAP these warrants have been recorded in equity. Under IFRS, the warrants are recorded as a derivative liability at fair value at issuance and at the end of each reporting period, with changes in fair value being recorded in income in the same manner as the convertible preferred shares above.

(v) Exploration and evaluation assets and property plant and equipment

Under Canadian GAAP, the Company applied the full cost method of accounting for oil and gas exploration, development and production activities. Under the full cost method, all costs associated with these activities were capitalized. Under IFRS, the Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

- exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP;

- non oil and gas assets (corporate assets) were reclassified from the full cost pool to property plant and equipment;

- LNG Project related costs were identified as intangible start-up costs and reclassified from the full cost pool to property plant and equipment; and

- the remaining full cost pool was allocated to the producing/development assets and components pro rata using reserve values.

The Company's exploration and evaluation assets consist of its undeveloped Western Canada land and North Africa offshore assets. Undeveloped land costs identified as exploration and evaluation assets pertain to only those undeveloped sections that the Company intended to actively pursue through its upcoming development programs. Exploration and evaluation assets were assessed for impairment on the IFRS transition date as described in section (vi). Corporate assets and LNG Project costs were also adjusted out of the full cost pool as these were considered non-oil and gas related costs and therefore not subject to the application of the deemed cost exemption. Corporate assets and the LNG Project were evaluated for impairment and subsequently recorded at their carrying values in property plant and equipment.

(vi) Impairments

Under Canadian GAAP, an item of property plant and equipment is deemed recoverable if the undiscounted future cash flows exceed the carrying value of the asset group. Under IFRS, recoverability or property plant and equipment is based on the higher of fair value less costs to sell and value in use of the CGU.

During the 2010 comparative period, ceiling test impairments were recognized under Canadian GAAP at June 30, 2010 and December 31, 2010. Under IFRS, The Company evaluated these assets for indicators of impairment at each reporting period resulting in further impairment adjustments recorded at June 30, 2010 and December 31, 2010 in relation to the Company's Western Canada producing and developed assets. Impairments were the result of declining long-term natural gas prices resulting in the carrying value of these CGU's exceeding their recoverable amounts. Recoverable amounts have been determined using fair value less costs to sell and value in use (the net present value of the cash flow or benefit that an asset generates for a specific use) of each CGU.

(vii) Depletion and depreciation

Under IFRS, the Company adopted a policy of depleting its producing and developed oil and gas assets on a unit of production basis over estimated proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. Under Canadian GAAP, depletion was calculated using all of Canada as a single cost centre. IFRS requires depletion and depreciation to be calculated based on individual components (ie. fields or combinations thereof) or CGU's.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(viii) Exploration costs and other income

Under Canadian GAAP, all exploration costs were capitalized in accordance with the full-cost method of accounting for oil and gas assets. Exploration costs identified under IFRS include those costs associated with leases and licences related to undeveloped land that are no longer being actively pursued by the Company as part of its development program. These costs have been recorded as an adjustment from property, plant and equipment to exploration costs during 2010.

IFRS adjustments related to other income relate to a refund of Nova Scotia offshore work deposits that were recorded against property, plant and equipment under Canadian GAAP during 2010. Under IFRS, carrying value associated with Nova Scotia offshore leases were impaired as part of the application of deemed cost under IFRS 1 on the IFRS transition date. These refunds have been adjusted from property plant and equipment to other income during 2010.

(ix) Provisions

Under IFRS, onerous contracts arise when the costs of meeting the obligations of a contract exceed the benefits to be derived from the agreement. When an onerous contract arises, IFRS requires that a provision be set up for the present obligation of the contract. The Company has lease agreements for office space which it no longer uses, resulting in costs of the agreements outweighing its benefits. Under IFRS, the leases are considered onerous in which case a provision has been recorded on the IFRS transition date as an adjustment to retained earnings. During 2010, the change in provision is recorded as a reduction against general and administrative expense.

(x) Share-based payments

Under Canadian GAAP, the Company recognized an expense related to share based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiplier. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate.

(xi) Foreign currency translation

IFRS 1 allows companies to deem the cumulative translation difference to be zero at transition date. The gain or loss on a subsequent disposal of any foreign operation then excludes the translation differences that arose before the date of transition to IFRS. The Company has elected to apply this exemption.

When an entity elects to use a deemed cost exemption for certain assets on initial adoption of IFRS, it calculates the cumulative translation amount for those assets not from the date of acquisition but from the date at which the deemed cost amount is determined. The Company has elected to apply the deemed cost exemption for its oil and gas assets as at the date of transition. Therefore oil and gas assets relating to foreign operations identified with a functional currency of U.S. dollars will not be adjusted for foreign exchange differences as the deemed cost has established its reporting currency value. The functional currency carrying value for these assets have been determined by applying the Canadian dollar to U.S. dollar spot rate at the IFRS transition date to the deemed cost amounts.

The financial information for those operations for which the functional currency is concluded to be different from the Company's reporting currency of Canadian dollars is the LNG Project, Trinidad and Tobago and North Africa. The only adjustment required at the IFRS transition date is to the decommissioning provision balance for the Company's Block 5(c) Trinidad and Tobago wells. Foreign exchange adjustments during the 2010 comparative period are required for all non-monetary assets and liabilities. The restatement from functional currency to reporting currency on all assets and liabilities have been recorded in other comprehensive income and accumulated under foreign currency translation reserve.

5. Reconciliation of statement of financial position from Canadian GAAP to IFRS (continued)

(xii) Flow-through shares

Under Canadian GAAP, proceeds from flow-through shares are recorded to share capital. When the tax benefits have been renounced to the flow-through shareholder, the Company records a reduction in share capital with a corresponding increase in the future income tax liability. Under IFRS, share capital for flow-through shares issued is recorded to share capital at the quoted value of the shares at the date of issuance. The difference between the quoted value and the gross proceeds received on the issuance of the shares is recorded as a liability. The tax cost resulting from deduction renouncement, less any proceeds received in excess of the quoted value of the shares, must be included in the determination of the tax expense. The Company's last issuance of flow-through shares was in 2008 resulting in the difference being applied as an increase to share capital with an offset to opening deficit on the IFRS transition date.

(xiii) Correction from previous reporting

In the course of preparing these condensed consolidated financial statements management identified an error in the application of IFRS on initial adoption. The Company had previously recognized an impairment of $8.4 million related to exploration and evaluation assets upon initial adoption of IFRS at January 1, 2010. Management has determined that the timing of this impairment was incorrect and that the assets should have been impaired to exploration expense in the quarter ended December 31, 2010. The impact is that exploration and evaluation assets and shareholder's equity were understated by $8.4 million at both January 1, 2010 and March 31, 2010, while exploration expense was understated by $8.4 million for the year ended December 31, 2010. This has been corrected in the reconciliations from Canadian GAAP to IFRS and on the statement of financial position as at January 1, 2010.

6. Discontinued operations

(a) Trinidad and Tobago

On December 22, 2010 the Company entered into an agreement to sell its remaining 25% interest in Block 5(c) and the Mayaro-Guayaguayare block ("MG Block") exploration and production license for an aggregate purchase price of US$87.5 million plus interest on the outstanding balance prior to closing. The transaction closed on June 22, 2011 for gross proceeds of US$78.1 million and the assumption of the Company's performance guarantee provided for the MG Block of US$12.0 million. The purchaser legally guaranteed the performance guarantee, resulting in a receivable with the legal right to offset the Company's obligation regarding the MG Block. The Company has recorded this as a receivable offsetting the MG block performance guarantee liability as further discussed in Note 17.

On February 8, 2011, as part of the agreement, the Company issued a US$20.0 million debenture to the purchaser. The debenture accrued interest at 6.0% per annum and was secured against the Company's Block 5(c) interests. Upon closing of the agreement, the US$20.0 million was applied against the proceeds of US$78.1 million. Upon closing the agreement the Company was eligible to reclaim US$20.0 million ($19.3 million in Canadian dollars) held as restricted cash with BG International Limited ("BG"). On August 4, 2011 the Company received payment of the US$20.0 million.

Proceeds from disposition		(CDN$ thousands)
Cash received		56,596
Debenture retired		19,898
MG Block Performance Guarantee Assumed by Purchaser		11,716
Transaction costs		(595)
Net proceeds		87,615
Net assets disposed at carrying value		
Exploration and evaluation assets		79,690
Decommissioning provisions	(3,040)	
Net assets		76,650
Gain before understated		10,965
Realized foreign currency translation reserve, reclassified from shareholder's equity		(5,976)
Net gain on disposition		4,989

(b) LNG Project

On February 22, 2011, the Company completed the sale of its wholly owned subsidiary Liberty Natural Gas LLC which owns a 100% working interest in the LNG Project to an entity related to West Face Capital Inc. ("West Face"). Pursuant to the sale, the Company received US$1.0 million for reimbursable costs between January 1, 2011 and February 22, 2011. The Company is entitled to receive deferred cash consideration of US$12.5 million payable upon West Face's first successful gas delivery. No amounts have been recorded in these consolidated financial statements related to this contingent consideration.

6. Discontinued operations (continued)

(c) Financial information from discontinued operations

The assets and liabilities of discontinued operations presented on the consolidated statements of financial position are as follows:

	Trinidad and Tobago			LNG Project			Total		
	June 30 2011	December 31 2010	January 1 2010	June 30 2011	December 31 2010	January 1, 2010	June 30 2011	December 31, 2010	January 1 2010
(CDN$ thousands)									
Assets									
Restricted cash	--	19,892	20,910	--	--	--	--	19,892	20,910
Accounts receivable	2	--	2,824	12	--	--	14	--	2,824
Prepaid expenses and deposits	26	20	48	--	36	37	26	56	85
Exploration and evaluation assets	--	80,744	69,998	--	--	--	--	80,744	69,998
Property, plant and equipment	--	--	--	--	--	18,974	--	--	18,974
	28	100,656	93,780	12	36	19,011	40	100,692	112,791
Liabilities									
Accounts payable and accrued liabilities	1,127	12,638	752	43	1,069	1,041	1,170	13,707	1,793
Decommissioning provision	--	2,943	2,763	--	--	--	--	2,943	2,763
	1,127	15,581	3,515	43	1,069	1,041	1,170	16,650	4,556

Net loss from discontinued operations reported in the consolidated statement of operations, comprehensive loss and deficit is as follows:

	Trinidad and Tobago		LNG Project		Total	
For the six months ending June 30	2011	2010	2011	2010	2011	2010
(CDN$ thousands)						
Expenses						
General and administrative	(534)	--	(908)	--	(1,442)	--
Finance costs	(493)	(64)	--	--	(493)	(64)
Gain (loss) on disposition of foreign operations, net of realized foreign currency translation	4,989		(389)		4,600	
Income (loss) from discontinued operations	3,962	(64)	(1,297)	--	2,665	(64)
Foreign currency translation gain (loss) relating to assets and liabilities held for sale	(1,148)	1,281	20	865	(1,128)	2,146
Reclassified from foreign currency translation to net earnings	5,976	--	389	--	6,365	--

Total comprehensive income (loss) from discontinued operations	8,790	1,217	(888)	865	7,902	2,082

	Trinidad and Tobago		LNG Project		Total	
For the three months ending June 30 (CDN$ thousands)	2011	2010	2011	2010	2011	2010
Expenses						
General and administrative	(400)	--	(8)	--	(408)	--
Finance costs	(301)	(31)	--	--	(301)	(31)
Gain (loss) on disposition of foreign operations, net of realized foreign currency translation	4,989	--	(389)	--	4,600	--
Income (loss) from discontinued operations	4,288	(31)	(397)	--	3,891	(31)
Foreign currency translation gain (loss) relating to assets and liabilities held for sale	542	4,231	8	1,462	550	5,693
Reclassified from foreign currency translation to net earnings	5,976	--	389	--	6,365	--
Total comprehensive income (loss) from discontinued operations	10,806	4,200	--	1,462	10,806	5,662

7. Exploration and evaluation assets & Property, plant and equipment, net

	June 30, 2011			December 31, 2010		
	Cost	Accum DD&A	Carrying value	Cost	Accum DD&A	Carrying value
Exploration and evaluation assets						
Beginning of period	49,361	--	49,361	12,526	--	12,526
Additions	14,776	--	14,776	46,443	--	46,443
Transfers to PP&E assets	(2)	--	(2)	--	--	--
Impairments, to exploration expense	(358)	--	(358)	(9,114)	--	(9,114)
Foreign exchange	(1,535)	--	(1,535)	(494)	--	(494)
End of period	62,242	--	62,242	49,361	--	49,361
Property, plant and equipment						
Beginning of period	161,165	(58,562)	102,603	146,672	(994)	145,678
Additions	8,283	--	8,283	14,493	--	14,493
Transfers from E&E assets	2	--	2	--	--	--
Depreciation and depletion	--	(6,243)	(6,243)	--	(16,795)	(16,795)
Impairments	--	--	--	--	(40,773)	(40,773)
End of period	169,450	(64,805)	104,645	161,165	(58,562)	102,603

During the six month period ended June 30, 2011, the Company capitalized $1.8 million (year ended December 31, 2010 – $5.4 million) of general and administrative expenses related to exploration and development activities of continuing operations and nil (December 31, 2010 - $12.9 million) of general and administrative expenses related to exploration and development activities of discontinued operations.

Exploration and evaluation assets consist of the Company’s exploration projects which are pending the determination of proved or probable reserves. Additions represent the Company’s share of costs incurred on exploration and evaluation assets during the period. All property, plant and equipment are held in Canada. Exploration and evaluation assets are divided geographically as follows:

	June 30 2011	December 31 2010	January 1 2010
Canada	6,416	2,956	8,968
North Africa	55,826	46,405	3,558
	62,242	49,361	12,526

8. Financial instruments

Cash and cash equivalents and restricted cash are financial assets designated at fair value through profit or loss. Gains or losses related to periodic revaluation at each reporting period are recorded to net income or loss. Cash and cash equivalents and restricted cash are transacted in active markets and have been classified using Level 1 inputs.

Accounts receivable are classified as loans and receivables and are initially measured at their fair value. Subsequent periodic revaluations are recorded at their amortized cost using the effective interest method.

Accounts payable and accrued liabilities, the provisions, convertible preferred shares, demand loan and revolving credit facility are classified as other liabilities and are initially measured at fair value. Subsequent periodic revaluations are recorded at their amortized cost using the effective interest method.

Derivatives, stock unit awards and restricted stock units are designated at fair value through profit or loss. Gains or losses related to periodic revaluation at each reporting period are recorded to net income or loss.

8. Financial instruments (continued)

The following tables provide fair value measurement information for financial assets and liabilities as of June 30, 2011 and December 31, 2010. The carrying value of cash and cash equivalents, restricted cash, trade and other receivables, provisions, accounts payable and accrued liabilities, convertible preferred shares, demand loan, revolving credit facility and the Trinidad debenture included in the consolidated statement of financial position approximate fair value due to the short term nature of those instruments. These assets and liabilities are not included in the tables.

			Fair value measurements using:		
As at June 30, 2011	Carrying value	Fair value	Level 1	Level 2	Level 3
Financial assets:					
Term deposits	28,935	28,935	--	28,935	--
Commodity contracts	410	410	--	410	--
Financial liabilities					
Commodity contracts	1,139	1,139	--	1,139	--
Derivative liability – warrants	155	155	--	155	--
Conversion feature on convertible preferred shares	2,158	2,158	--	--	2,158

			Fair value measurements using:		
As at December 31, 2010	Carrying value	Fair value	Level 1	Level 2	Level 3
Financial liabilities					
Derivative liability – warrants	404	404	--	404	--
Conversion feature on convertible preferred shares	4,695	4,695	--	--	4,695

The Company uses a fair value hierarchy to categorize the inputs used to measure the fair value of its financial instruments.

Level 1 Fair Value Measurements

Level 1 fair value measurements are based on unadjusted quoted market prices. The Company did not have any financial instruments classified as level 1.

Level 2 Fair Value Measurements

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Term deposits – Term deposits are a cash equivalent that is measured at fair value as provided by the Company's financial institution.

Commodity contracts – The fair value of risk management contracts are provided by the Company's financial institution, marked to market forward prices.

Derivative liability on warrants – The fair value of the conversion feature is determined using a Black Scholes model. The assumptions included in the model include the risk-free discount rate, volatility and expected dividend rates.

8. Financial instruments (continued)

Level 3 Fair Value Measurements

Level 3 fair value measurements are based on unobservable information.

Conversion features on preferred shares – The fair value of the conversion feature is determined using a binomial lattice approach. The assumptions included in the model include the risk-free discount rate, volatility, expected dividend rates, conversion price and forced conversion price.

The following table summarizes the carrying value of the liability and equity components of the convertible preferred shares:

	Liability component		Conversion feature		Total
	Series A shares	Series B shares	Series A shares	Series B shares	
Balance, January 1, 2010	15,301	--	--	--	15,301
Accreted non-cash interest, pre conversion	44	--	--	--	44
Loan restructuring	(15,345)	15,517	--	3,415	3,587
Accreted non-cash interest, post conversion	--	119	--	--	119
Fair value change conversion feature	--	--	--	1,371	1,371
Foreign exchange	--	(839)		(91)	(930)
Balance, December 31, 2010	--	14,797	--	4,695	19,492
Accreted non-cash interest	--	(17)	--	--	(17)
Fair value change conversion feature	--	--	--	(2,396)	(2,396)
Foreign exchange	--	(447)	--	(141)	(588)
Balance, June 30, 2011	--	14,333	--	2,158	16,491

All components of the Series B shares have been classified as current at June 30, 2011 and December 31, 2010.

9. Risk Management

In order to manage the Company's exposure to credit risk, foreign exchange risk, interest rate and commodity price risk, the Company developed a risk management policy. Under this policy, it may enter into agreements, including fixed price, forward price, physical purchases and sales, futures, currency swaps, financial swaps, option collars and put options. The Company's Board of Directors evaluates and approves the need to enter into such arrangements.

Credit risk

Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of nonpayment. The Company mitigates risk from joint venture partners by obtaining partner approval of capital expenditures prior to starting a project.

9. Risk Management (continued)

The Company's accounts receivable are with natural gas and liquids marketers, the Government of the Republic of Trinidad and Tobago and joint venture partners in the petroleum and natural gas business under substantially normal industry sale and payment terms and are subject to normal credit risks. The Company's credit risk exposure is as follows:

	June 30 2011	December 31 2010
(CDN$ thousands)		
Western Canada joint interest billings	210	3,212
Goods and Services Tax receivable	1,461	139
North Africa recoverable expenses	121	--
Revenue accruals and other receivables	4,142	3,796
Accounts receivable included in assets of discontinued operations	14	--
Loans and receivables	5,948	7,147
Cash and cash equivalents	40,837	2,649
Restricted cash	19,290	19,892
Financial assets designated at fair value through profit or loss	410	--
Credit exposure	66,485	29,688

The Company's allowance for doubtful accounts is currently $2.1 million (December 31, 2010 – $3.0 million). These amounts offset $1.8 million in value added tax receivable from the Government of the Republic of Trinidad and Tobago (December 31, 2010 – $1.8 million), $0.3 million of Western Canada joint interest and miscellaneous receivables (December 31, 2010 – $0.3 million) and nil withholding tax receivable on preferred share dividends (December 31, 2010 – $0.9 million) that the Company considers past due.

Foreign exchange risk

The Company is exposed to foreign currency fluctuations as oil and gas prices received are referenced to U.S. dollar denominated prices. The Company's foreign exchange risk denominated in U.S. dollars is as follows;

	June 30 2011	December 31 2010
(US$ thousands)		
Cash and cash equivalents	30,805	1,744
Restricted cash	20,000	20,000
Foreign denominated financial assets	50,805	21,744

	June 30 2011	December 31 2010
(US$ thousands)		
Block 5(c) payables included in liabilities held for sale	1,169	285
MG Block payables included in liabilities held for sale	--	12,040
North Africa payables	3,596	7,947
Mariner swap provision	12,500	12,500
Convertible preferred shares	14,861	14,878

Conversion feature on convertible preferred shares	2,237	4,720
Derivative liability - warrants	161	355
Foreign denominated financial liabilities	34,524	52,725

9. Risk Management (continued)

These balances are exposed to fluctuations in the U.S. dollar. In addition, the Company is exposed to fluctuations between U.S. dollars and the domestic currencies of Trinidad and Tobago and Tunisia. At this time, the Company has chosen not to enter into any risk management agreements to mitigate foreign exchange risk. The Company's exposure to foreign currency exchange risk on its comprehensive loss, assuming reasonably possible changes in the U.S. dollar to Canadian dollar foreign currency exchange rate of +/- one cent is $0.6 million. This analysis assumes all other variables remain constant.

Interest rate risk

The Company is exposed to interest rate risk as the credit facilities bear interest at floating market interest rates. The Company has no interest rate swaps or hedges to mitigate interest rate risk at June 30, 2011. The Company's exposure to fluctuations in interest expense on its net loss and comprehensive loss, assuming reasonably possible changes in the variable interest rate of +/- 1% is $0.1 million. This analysis assumes all other variables remain constant.

Commodity price risk

The Company enters into commodity sales agreements and certain derivative financial instruments to reduce its exposure to commodity price volatility. These financial instruments are entered into solely for risk mitigation purposes and are not used for trading or other speculative purposes. The following commodity price risk contract was in place as of the date of this report.

Term	Contract	Volume (GJ/d)	Fixed Price ($/GJ)	Realized gain
March 1, 2011 – December 31, 2011	Swap	5,000	$4.11	$291

In exchange for receiving the fixed price on the February 14, 2011 Swap Agreement, the Company issued the following call option:

Term	Contract	Volume (Bbls/d)	Fixed Price (US$/Bbl)	Realized loss
March 1, 2011 – December 31, 2012	Call option	250	$100.00	($105)

10. Provisions

	June 30 2011	December 31 2010	January 1 2010
Mariner swap (note 17c)	12,056	12,433	--
Onerous contracts	30	259	1,146
Provisions	12,086	12,692	1,146

11. Short term debt

	June 30 2011	December 31 2010	January 1 2010
Credit facility A	131	20,251	24,067
Credit facility B	6,901	--	-
Convertible preferred shares	14,333	14,797	15,301
Short term debt	21,365	35,048	39,368

As at June 30, 2011, the Company had drawn $0.1 million (December 31, 2010 – $20.3 million) against the $40.0 million (December 31, 2010 - $40.0 million) demand revolving credit facility ("Credit Facility A") at a variable interest rate of prime plus 2.5% as at June 30, 2011 and prime plus 0.75% as at December 31, 2010. Credit Facility A is secured by a $100.0 million debenture with a floating charge on the assets of the Company and a general security agreement covering all the assets of the Company. Credit Facility A has covenants, as defined in the Company's credit agreement, that require the Company to maintain its working capital ratio at 1:1 or greater and to ensure that non-domestic general and administrative expenditures in excess of $7.0 million per year and all foreign capital expenditures are not funded from Credit Facility A nor domestic cash flow while Credit Facility A is outstanding.

On February 22, 2011, the Company obtained an additional $20.0 million development demand loan ("Credit Facility B") at a variable interest rate of 50 basis points above the variable interest rate on Credit Facility A. Credit Facility B will be used to assist in the acquisition of producing petroleum and natural gas reserves and/or development of proved producing/undeveloped petroleum and natural gas reserves. Subject to availability, review, and the Company's creditor's right of demand, principal and interest shall be repaid over the half-life of the reserves being financed. As at June 30, 2011 the Company had drawn $6.9 million against the $20.0 million secured facility.

As at December 31, 2010, the Company was in violation of one of its debt covenants. This covenant placed a ceiling on foreign expenditures that was exceeded pending the approval of the Trinidad and Tobago asset sale. The Company sought and received a waiver from its lender on this violation and it does not impact the Company's borrowing ability. As at June 30, 2011 the Company was in compliance with its debt covenants.

The Company is subject to the next semi-annual review of its credit facilities on or before October 1, 2011.

On February 3, 2010, the Company restructured the terms of the Series A, 5.0% US Cumulative Redeemable Convertible Preferred Shares (the "Series A Shares"). Pursuant to the terms of the restructuring, the Series A Shares were exchanged on a share for share basis for 150,000 First Preferred Shares, Series B shares (the "Series B Shares") pursuant to which the redemption date was extended from December 31, 2010 to December 31, 2011, the conversion price was reduced from US$12.50 to US$3.00 and the conversion of 150,000 preferred shares into common shares was increased from 1,200,000 to 5,000,000. The terms of the dividend payment under the Series B Shares remain unchanged from the Series A Shares whereby the Company can elect to pay the quarterly dividend by way of issuance of common shares at market, based on a 5.75% annualized dividend rate in lieu of the 5.0% annualized cash dividend rate. The dividend rate was increased by 1/30 of 1% per day restricted to the 150 day period after December 31, 2010 and thereafter reverted to 5.0%. In addition, the Company granted 500,000 common share purchase warrants exercisable at a price of US$3.25 for each common share expiring December 31, 2011. The Series B shares are redeemable by the Company on or after December 31, 2011 and retractable by the Series B shareholders on December 31, 2011. The Company can force conversion of the Series B Shares at anytime in the future if its common shares close at a price of at least a 100% premium to the conversion price of US$3.00 on a major US exchange for 20 out of any 30 consecutive trading days while the common shares underlying the Series B Shares are registered.

The Company recorded the exchange of the Series A Shares for the Series B Shares as a deemed settlement of the Series A Shares. The liability component of the Series B Shares was recorded at their new fair value based on the revised terms. The increase in the liability of $0.2 million on February 3, 2010, was charged to earnings during the year ended December 31, 2010. The conversion feature and the issuance of common share purchase warrants have been recorded as financial derivative liabilities (Note 8).

During the six months ended June 30, 2011 and the year ended December 31, 2010 the Company elected to pay cash as opposed to common shares to satisfy its quarterly preferred shares dividend requirements.

12. Revenue

The following summarizes the Company's revenue:

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Petroleum and natural gas sales	9,599	8,720	18,976	18,894
Royalties	(1,705)	(1,628)	(2,150)	(3,134)
	7,894	7,092	16,826	15,760

13. Operating expense

Operating costs for the Company are as follows:

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Operating	2,989	2,591	6,106	5,467
Well workovers	215	100	803	100
	3,204	2,691	6,909	5,567

14. Financing costs

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Accretion on decommissioning provision	167	169	323	358
Interest on credit facilities	383	105	632	158
Interest on preferred shares	252	233	498	491
	802	507	1,453	1,007

15. Stock based compensation

(a) Stock option plan

The Company has a stock option plan for its directors, officers and employees. The exercise price for stock options granted is the quoted market price on the grant date vesting over a three year period. Options under the equity based stock option plan vest over three years with a maximum term of ten years. Options under the liability based stock option plan vest over four years with a maximum term of five years.

	Six months ended June 30, 2011		Twelve months ended December 31,2010	
(CDN$ thousands, except per share price)	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Balance, beginning of period	1,910	$5.78	1,978	$9.10

Cancelled	--	--	(258)	11.90
Forfeited	(463)	9.32	(792)	8.67
Granted	1,712	3.63	982	3.08
Balance, end of period	3,159	4.10	1,910	5.78

15. Stock based compensation (continued)

The following table summarizes stock options outstanding under the plan at June 30, 2011:

	Options outstanding			Options exercisable	
Exercise price ($)	Number of options (thousands)	Average remaining contractual life (years)	Weighted average exercise price ($)	Number of options (thousands)	Weighted average exercise price ($)
2.81 – 4.00	1,974	7.40	3.01	585	3.07
4.01 – 6.00	916	9.54	4.29	419	4.30
6.01 – 10.00	103	2.78	8.47	103	8.47
10.01 – 15.00	94	5.13	11.33	94	11.33
15.01 – 18.90	72	6.39	15.82	68	15.76
2.81 – 18.90	3,159	7.78	4.10	1,269	5.21

The fair value of options granted during the period was estimated based on the date of grant using a Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

	Six months ended June 30 2011	Twelve months ended December 31 2010
Share price ($)	3.63	3.08
Exercise price ($)	3.63	3.08
Risk free rate (%)	2.2	2.1
Expected life (years)	4.1	3.8
Expected dividend yield (%)	--	--
Expected volatility (%)	141.8	122.8
Weighted average fair value of options granted	3.21	2.54

A forfeiture rate of 27.7% (December 31, 2010 – 16.9%) is used when recording stock based compensation. This estimate is based on the historical forfeiture rate and adjusted to the actual forfeiture rate. Stock based compensation cost of $3.8 million incurred for the six month period ending June 30, 2011 (June 30, 2010 - $1.1 million) was expensed. No stock based compensation expense was capitalized during the first six months of 2011 or 2010.

(b) Employee stock savings plan

The Company has an employee stock savings plan (“ESSP”) in which employees are provided with the opportunity to receive a portion of their salary in common shares, which is then matched on a share for share basis by the Company. The Company purchased approximately 59,562 shares on the open market under the ESSP during the six months ended June 30, 2011 (June 30, 2010 – 39,704 shares).

(c) Stock unit awards

As at June 30, 2011, the Company has issued 1.3 million (December 31, 2010 – 0.7 million) stock unit awards to the Company's executive officers and Board of Directors. A stock unit is the right to receive a cash amount equal to the fair market value of one common share of the Company. The stock units have time and share based performance vesting terms which vary depending on whether the holder is an executive officer or director. If subsequent to the grant date, the shareholders of the Company approve an equity compensation plan under which the stock units may be paid with common shares of the Company, then the Board may determine that the units may be paid in cash or common shares. As of June 30, 2011, the Company recorded a liability of $1.3 million to recognize the fair value of the vested stock units (December 31, 2010 - $1.0 million).

(d) Restricted share units

The Restricted Share Unit Plan became effective on March 24, 2011, to attract and retain experienced personnel with incentive compensation tied to shareholder return. Under the plan, each grantee will be entitled to, in respect of each Restricted Share Unit ("RSU"), a cash amount equal to the fair market value of one common share in the capital of the Company on such vesting date, with the vesting subject to a minimum floor share price.

15. Stock based compensation (continued)

The following table summarizes RSUs outstanding under the plan at June 30, 2011:

	Units outstanding			Units exercisable	
Floor price ($)	Number of units (thousands)	Average remaining contractual life (years)	Weighted average floor price ($)	Number of units (thousands)	Weighted average floor price ($)
0.00 – 3.00	295	2.31	1.98	104	2.52
3.01 – 3.50	42	2.54	3.13	--	--
3.51 – 3.64	12	2.54	3.64	--	--
0.00 – 3.64	349	2.34	2.18	104	2.52

RSUs issued during the period were initially valued at the grant date and revalued at June 30, 2011 using a binomial lattice approach with weighted average assumptions as follows:

	Valuation at June 30 2011	Valuation at grant date
Share price ($)	3.13	2.55
Risk free rate (%)	1.5	1.5
Expected life (years)	2.3	2.4
Expected volatility (%)	55	55
Weighted average fair value	2.77	2.10

The following table summarizes stock based compensation expense:

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Equity based stock option expense	757	476	2,446	901
Liability based stock option expense	212	--	212	--
Stock unit award expense	339	85	780	152
Restricted share unit expense	361	--	361	--
Stock based compensation expense	1,669	561	3,799	1,053

The following table summarizes the stock based compensation liability:

	June 30 2011	December 31 2010	January 1 2010
Stock option based liability	212	--	--
Stock unit award liability	1,311	530	55
Restricted share unit liability	361	--	--
Stock based compensation liability	1,884	530	55

16. Supplemental cash flow information

Changes in non-cash working capital

	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Accounts receivable	1,434	(3,384)	1,199	(757)
Prepaid expenses and deposits	297	(2,657)	457	(2,231)
Accounts payable and accrued liabilities	(12,785)	603	(15,685)	(12,292)
Provisions	(71)	(223)	(606)	(445)
Accrued interest	163	--	--	--
Change in non-cash working capital	(10,962)	(5,661)	(14,635)	(15,725)

The change in non-cash working capital has been allocated to the following activities:

	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Operating	1,654	703	1,089	(4,985)
Financing	--	--	--	--
Investing	(12,616)	(6,364)	(15,724)	(10,740)
	(10,962)	(5,661)	(14,635)	(15,725)

Cash and cash equivalents were comprised of the following:

	June 30 2011	December 31 2010	January 1 2010
Cash held in banking institutions	11,902	2,649	3,305
Term deposits with short term maturities	28,935	--	--
Cash and cash equivalents	40,837	2,649	3,305

The Company's policy is to invest excess cash in highly liquid short-term investment instruments with minimal principal risk.

17. Contingencies and commitments

(a) MG Block Trinidad and Tobago

In 2007, the Company received an exploration and development license from the Government of Trinidad and Tobago on the MG Block and as a result was committed to conducting 3D seismic by the end of 2009 and to drill two exploration wells on the MG block in a joint venture with The Petroleum Company of Trinidad and Tobago Limited ("Petrotrin"). The first well had to be drilled to a depth of at least 3,000 meters by January 2010 and the second to a depth of at least 1,800 meters by July 2010. The Company agreed to provide a performance security to Petrotrin of US$12.0 million to meet the minimum work program.

17. Contingencies and commitments (continued)

The Company's agreement to sell its remaining interest in Block 5(c) and the MG Block includes the assumption of the performance guarantee. Upon closing the sale on June 22, 2011 the purchaser assumed the performance guarantee for the MG Block. While the rights to the MG Block were not transferred to the purchaser, this guarantee provides a receivable with the legal right to offset the US$12.0 million performance guarantee in discontinued operations (Note 6). Should the Company be required to pay the performance security amount in order to relinquish the MG Block, the purchaser will reimburse the Company for any amounts owing up to US$12 million. The Company expects that the purchaser's guarantee will offset any further liability with respect to the MG Block. As of June 30, 2011, the Company was in the process of ceasing all operations in Trinidad and exiting the country.

(b) North Africa

7th of November block

On August 27, 2008, the Company entered into the 7th of November Block Exploration and Production Sharing Agreement ("EPSA") with a Tunisian/Libyan company, Joint Exploration, Production, and Petroleum Services Company ("Joint Oil"). The EPSA contract area straddles the offshore border between Tunisia and Libya. Under terms of the EPSA, the Company has been named operator. Under the EPSA, the minimum work program for the first phase (four years) of the seven year exploration period includes the Zarat North-1 appraisal well, three exploration wells and 500 square miles of 3D seismic. The EPSA provides for penalties for non-fulfillment of the minimum work program of US$15.0 million per exploration well and up to US$4.0 million for 3D seismic not completed. The Company has provided a corporate security to a maximum of US$49.0 million to secure its minimum work program obligations. On January 11, 2011, the Company announced the successful drilling and production testing of its 100% working interest in the Zarat North–1 well. The well has been temporarily abandoned in a manner allowing it to be utilized for future development purposes while the Company evaluates reservoir characteristics and development options on a field development.

Political issues and Libyan sanctions

The governments of Tunisia and Libya are in political turmoil. During January 2011, protests in Tunisia led to the overthrow of the government. The Company safely evacuated its personnel and the rig and equipment without incident. Election of a new national constituent assembly is scheduled to take place later this year. While relative calm has been restored, uncertainty remains over the future direction of the country. Similarly, widespread protests over the government in Libya have occurred and a state of war exists between government and opposition forces. This has led to the cessation of oil production in the country and military intervention by Western forces. On February 26, 2011, the United Nations imposed sanctions on the Libyan government followed by consequent actions of the Canadian Government pursuant to the Special Economics Measures Act (Canada) (the "Libyan Sanctions"). While this turmoil has not had a direct impact on the Company's 7th of November Block evaluation of the Zarat North-1 results and planning of future activities, it may significantly and adversely affect the Company in various ways, including the functioning of Joint Oil, the pace of future development plans and activities, the ability to secure supplies and personnel, the ability to make payments to Joint Oil and the ability to attract joint venture partners or financing.

All of the activity related to this concession will be monitored by the Company to ascertain the impact of the turmoil in Tunisia and Libya and the impact, if any, of the Libyan Sanctions. The imposition of sanctions and the state of war are unforeseen circumstances beyond the control of the Company, which render the performance of Sonde's obligations impossible and thus constitute a condition of Force Majeure. As a result, the Company made a formal Force Majeure declaration to Joint Oil for the 7th of November Block on June 7, 2011. This declaration effectively puts the term of the EPSA on hold, without penalty, pending the resolution of political sanctions and instability in Libya. Joint Oil has questioned the Company's declaration of Force Majeure and requested that the Company continue to perform under the ESPA. The Company believes that the declaration of Force Majeure is sound and, if challenged, will be upheld.

(c) Swap agreement

At the time it entered into the North Africa EPSA, the Company also signed a "Swap Agreement" awarding an overriding royalty interest and optional participating interest to Joint Oil, in the Company's "Mariner" Block, offshore Nova Scotia, Canada. If at the end of August 2011, no well has been drilled on the Mariner Block, Joint Oil has the right to put back and sell the overriding royalty to the Company for US$12.5 million. On December 31, 2010, the Mariner Block license lapsed resulting in the Company no longer holding any interest in offshore Nova Scotia, Canada. As a result, Joint Oil would be eligible to exercise its option on or after August 27, 2011. The Libyan Sanctions prohibit the Company from honring the option.

17. Contingencies and commitments (continued)

(d) Commitments

At June 30, 2011, the Company has committed to future payments over the next five years, as follows:

	2011	2012	2013	2014	2015	Thereafter	Total
Accounts payable and accrued liabilities	14,978	--	--	--	--	--	14,978
Stock based compensation liability	1,844	--	--	--	--	--	1,844
Mariner swap	12,056	--	--	--	--	--	12,056
Derivative financial liabilities	3,452	--	--	--	--	--	3,452
Short term debt	21,365	--	--	--	--	--	21,365
Liabilities of discontinued operations	1,170	--	--	--	--	--	1,170
Office rent	773	1,142	--	--	--	--	1,915
Equipment	6	8	--	--	--	--	14
	55,644	1,150	--	--	--	--	56,794

(e) Litigation and claims

In December 2009, a class action lawsuit was commenced in the United States District Court of the Southern District of New York against certain former executive officers of the Company for allegedly violating the United States Securities and Exchange Act of 1934 by failing to disclose information concerning its prospects in Trinidad and Tobago. In addition, in May and June 2010, two proposed class action lawsuits were commenced in the Ontario Superior Court of Justice. The actions are made against different groups of former executives and directors of the Company. One of the actions alleges oppression and improper option granting practices and includes the Company and Challenger, a wholly owned subsidiary of the Company, as defendants. The actions contain various claims relating to allegations of misrepresentation and failure to disclose information concerning the Company's activities in Trinidad and Tobago. The class action lawsuits purport to be brought on behalf of purchasers of common shares of the Company from January 14, 2008 to February 17, 2009.

On October 25, 2010, a memorandum of understanding (“MOU”) was entered into whereby the parties to the class action lawsuits and the former executive officers agreed to settle the Litigation upon the terms and conditions set forth in the MOU, subject to court approval and all other conditions to the settlement to be mutually agreed upon in a final stipulation of settlement (the “Stipulation”).

Under the terms of the MOU, the parties have agreed that the Stipulation will provide, among other things, for the full and final disposition of the Litigation, with prejudice and without costs, by the establishment of a US$5.2 million settlement fund by the Defendants’ insurers for the benefit of a settlement class which shall consist of all those who purchased securities of the Company between January 14, 2008 and February 17, 2009. Pending the negotiation and execution of the Stipulation, the parties to the Litigation will ask the presiding courts to continue the stay of all proceedings in the Litigation, except as necessary to consummate the settlement. While the Company believes that the stipulation will ultimately be consummated, no assurance can be provided.

The Defendants continue to deny any and all liability under securities laws and that they committed any violations of law or engaged in any wrongful acts, and that the settlement is being agreed to in order to eliminate the burden and expense of further litigation.

In addition, the Company may be involved in various claims and litigation arising in the ordinary course of business. In the opinion of the Company the various claims and litigations arising there from are not expected to have a material adverse effect on the Company's financial position or its results of operations. The Company maintains insurance, which in the opinion of the Company, is in place to address any unforeseen claims.

18. Subsequent event

On August 4, 2011 the Company received US$20.0 million that had been held as restricted cash with BG International Limited. The funds had a carrying value of $19.3 million at June 30, 2011 and were presented as restricted cash.

Document 2

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") has been prepared by management as of August 11, 2011 and reviewed and approved by the Board of Directors (the "Board") of Sonde Resources Corp. (the "Company"). This MD&A is a review of the operational results of the Company with disclosure of oil and gas activities in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Effective January 1, 2011 the Company adopted International Financial Reporting Standards ("IFRS"). This MD&A should be read in conjunction with the unaudited condensed consolidated financial statements and accompanying notes for the three and six months ended June 30, 2011 and 2010. In 2010, the Canadian Institute of Chartered Accountants Handbook was revised to incorporate IFRS and require publicly accountable companies to apply such standards effective January 1, 2011. The Company has commenced reporting on this basis. The term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS. The reporting currency is the Canadian dollar unless otherwise stated.

Non-IFRS Measures – This MD&A contains references to cash flow from (used for) operations, cash flow per share and operating netback, which are not defined under IFRS as issued by the International Accounting Standards Board and are therefore non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are, therefore, unlikely to be comparable to similar measures presented by other issuers. Management of the Company believes cash flow from (used for) operations, cash flow per share and operating netback are relevant indicators of the Company's financial performance, ability to fund future capital expenditures and repay debt. Cash flow from (used for) operations and operating netback should not be considered an alternative to or more meaningful than cash flow from operating activities, as determined in accordance with IFRS, as an indicator of the Company's performance. In the operating netback and cash flow from (used for) operations section of this MD&A, reconciliation has been prepared of cash flow from (used for) operations and operating netback to cash from operating activities, the most comparable measure calculated in accordance with IFRS.

Boe Presentation – Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil (6:1). This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boe's may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.

Share Presentation - On June 3, 2010, the Company's shareholders approved the consolidation of the Company's shares on a five for one basis effective on the close of business June 4, 2010. The effect of the consolidation was to reduce to one-fifth the number of common shares, warrants, stock options and stock unit awards outstanding. The number of shares into which the preferred shares are convertible were also reduced to one-fifth. In addition, the conversion price of the preferred shares, the weighted average exercise price and fair value per options, warrants and stock unit awards have been adjusted to five times the pre-consolidation prices. All share and per share amounts included in this MD&A have been adjusted retroactively for the consolidation.

Going concern – The Company's consolidated financial statements have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

Forward-Looking Statements – This interim MD&A contains information that constitutes "forward-looking information" or "forward-looking statements" (collectively "forward-looking information") within the meaning of applicable securities legislation. This forward-looking information includes, among others, statements regarding:

- business strategy, plans and priorities;
- expected sources of funding for the capital program;
- future costs, expenses and royalty rates and development, exploration and other expenses;
- expected volume and product mix of the Company's oil and gas production;
- future oil and gas prices and interest rates in respect of the Company's commodity risk management programs;
- other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance; and
- the Company's tax pools.

The completion of any contemplated disposition is contingent on various factors including market conditions, the ability of the Company to negotiate acceptable terms of sale and receipt of any required approvals of such dispositions. Information regarding business plans generally assumes that the extraction of crude oil, natural gas and natural gas liquids remains economic.

Undue reliance should not be placed on forward-looking information. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks which could cause actual results to vary and in some instances to differ materially from those anticipated by the Company and described in the forward-looking information contained in this interim MD&A. The material risk factors include, but are not limited to:

- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas, market demand and unpredictable facilities outages;
- risks and uncertainties involving geology of oil and gas deposits;
- uncertainty related to production, marketing and transportation;
- availability of experienced service industry personnel and equipment;
- availability of qualified personnel;
- the uncertainty of reserves and resources estimates, reserves life and underlying reservoir risk;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- delays due to adverse weather conditions;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- the outcome and effects of any future acquisitions and dispositions;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing and changes in capital markets;
- risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action);
- risks associated with competition from other producers;
- changes in general economic and business conditions; and
- the possibility that government policies or laws may change or government approvals may be delayed or withheld.

The foregoing list of risk factors is not exhaustive. Additional information on these and other factors which could affect the Company’s operations or financial results are included in the Company’s most recent Annual Information Form. In addition, information is available in the Company’s other reports on file with Canadian securities regulatory authorities and the United States Securities and Exchange Commission.

Forward-looking information is based on the estimates and opinions of the Company’s management at the time the information is presented. The Company assumes no obligation to update forward-looking information should circumstances or management’s estimates or opinions change, except as required by law.

Statements contained in this document relating to estimates, results, events and expectations are forward-looking statements within the meaning of Section 27A of the United States Securities Act of 1933, as amended and Section 21E of the United States Securities Exchange Act of 1934, as amended. These forward-looking statements involve known and unknown risks, uncertainties, scheduling, re-scheduling and other factors which may cause the actual results, performance, estimates, projections, resource potential and/or reserves, interpretations, prognoses, schedules or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such statements. Such factors include, among others, those described in the Company’s’ annual reports on Form 40-F or Form 20-F on file with the U.S. Securities and Exchange Commission.

Business Overview and Strategy

The Company is a Calgary, Alberta; Canada based energy company engaged in the exploration for and production of oil and natural gas. The Company's operations are located in Western Canada and offshore North Africa. On June 22, 2011 the Company completed the previously announced sale of its offshore operations in the Republic of Trinidad and Tobago ("Trinidad and Tobago"). The Trinidad and Tobago operations have been classified as discontinued operations in accordance with IFRS. In February 2011, the Company sold its interest in Liberty Natural Gas LLC ("Liberty"), a wholly owned subsidiary of the Company which has been involved in the development of a proposed liquefied natural gas project (the "LNG Project") in U.S. federal waters offshore the state of New Jersey. The dispositions of its Trinidad and Tobago operations and the LNG Project have allowed the Company to effectively recapitalize its balance sheet in order to focus its resources towards development in Western Canada.

The Company derives all of its production and cash flow from operations in Western Canada. The Company's Western Canadian oil and gas assets are primarily high working interest properties that are geographically concentrated in southern and west-central Alberta, the most significant being the Company's southern Alberta cash generating unit ("CGU") (or Greater Drumheller, Alberta area), which accounts for approximately 74% of the Company's production. The balance of production largely comes from the Kaybob/Windfall and Boundary Lake/Eaglesham areas in west-central Alberta, with minor production in north-eastern British Columbia. The Company holds a Western Canadian land position of 421,910 gross (289,993 net) acres.

In May and June the Company drilled and cased its first three horizontal wells in the Drumheller Mannville "I" pool at Drumheller. The program was designed to test the economic viability of re-developing the entire pool using horizontal drilling and multi-stage hydraulic fracturing technology ("fracs"). In late June, the Sonde 3-4 well was completed using 12 stages of gelled propane. The well has flowed unassisted for the subsequent 30 days at rates averaging 192 Boe/d. In late July, the Sonde 3-5 was completed with 15 stages of gelled water. The well will be placed on pump and tied-back to the Company's 9-9 central battery in early August. Sonde will report preliminary results on this well after gathering enough production data to obtain a reliable stabilized rate. Sonde elected to compare the two different frac types on the first two wells in order to more fully understand the range of development options and costs at an early stage in the program. When sufficient data is available on the 3-5 well, the Company will determine a preferred frac treatment and proceed with completing the third well, Sonde 14-14.

The Company plans to drill an additional six horizontal wells in Drumheller by the end of 2011, plus two horizontal development wells in the Kaybob/Windfall area and one horizontal exploration well in the emerging Duvernay oil resource play. Concentrating on liquids-rich opportunities has allowed the Company to decrease its gas / liquid ratio to approximately 74% in the three months ending June 30, 2011, as compared to approximately 79% gas in the same quarter last year.

The Company is focused on maximizing long-term sustainable value to its shareholders by:

- Developing the Western Canada asset base to increase average daily production, along with replacement of producing reserves on an economic and cost effective basis through exploitation, full-cycle exploration and strategic acquisition;
- Currently evaluating its entire acreage position in anticipation of an aggressive oil and liquids oriented, multi-year drilling program;
- Establishing organic growth through repeatable drilling programs;
- Providing shareholders access to high-leverage oil-oriented growth in Western Canada by purchasing a significant number annually of lease acreage in emerging "oil-resource" plays such as the Kaybob-area Duvernay; and
- Preserving our assets in North Africa while exploring options after Force Majeure is concluded.

The success of the Company's ongoing operations are dependent upon several factors, including but not limited to, the price of energy commodity products, the Company's ability to manage price volatility, increasing production and related cash flows, controlling costs, availability of experienced service industry personnel and equipment, capital spending allocations, the ability to attract equity investment, hiring and retaining qualified personnel and managing political and government risk, particularly with respect to its interests in North Africa.

Operating netback and cash flow from (used for) operations

Three months ended June 30, 2011	($ thousands) 2011	2010	% change	($ per boe) 2011	2010	% change
Revenue						
Petroleum and natural gas sales	9,599	8,720	10	40.82	33.13	23
Realized gain on financial instruments	110	923	(88)	0.47	3.51	(87)
Transportation	(257)	(333)	(23)	(1.09)	(1.27)	(14)
Royalties	(1,705)	(1,628)	5	(7.25)	(6.19)	17
	7,747	7,682	1	32.95	29.18	13
Operating	(2,989)	(2,591)	15	(12.71)	(9.85)	29
Well workover expense	(215)	(100)	115	(0.91)	(0.38)	
Operating netback(2)	4,543	4,991	(9)	19.33	18.95	2
Exploration	(206)	(41)	402	(0.88)	(0.16)	450
General and administrative	(2,553)	(3,359)	(24)	(10.86)	(12.76)	(15)
Foreign exchange gains	(307)	578	-	(1.31)	2.20	-
Interest and other income	3	169	(98)	0.01	0.64	(98)
Interest	(937)	(305)	207	(3.98)	(1.16)	243
Bad debt expense	-	(885)	-	-	(3.36)	-
Asset retirement expenditures	-	(35)	-	-	(0.13)	-
Part VI.1 tax on preferred share dividends	(120)	(386)	(69)	(0.51)	(1.47)	(65)
Cash flow from operations(1,2)	423	727	(42)	1.80	2.75	(35)
Changes in non-cash working capital	1,654	703	135	7.03	2.67	163
Cash from by operating activities (1)	2,077	1,430	45	8.83	5.42	63

(1) Table includes both continuing and discontinued operations.
(2) Non-IFRS measure.

For the three months ended June 30, 2011, cash flow from operations was $0.4 million compared to $0.7 million for the same period in 2010. This was a result of higher interest costs associated with short term debt and a lower operating netback. The lower operating netback in 2011 was primarily due to a lower realized gain on financial instruments relative to a hedging contract in place in 2010. Also contributing to a lower operating netback were increased fixed operating costs and higher chemical costs due to adverse weather conditions. Higher liquids prices, partially offset by lower production volumes, caused an increase in petroleum and natural gas sales.

Six months ended June 30, 2011	($ thousands) 2011	2010	% change	($ per boe) 2011	2010	% change
Revenue						
Petroleum and natural gas sales	18,976	18,894	-	39.39	36.81	7
Realized gain on financial instruments	186	1,133	(84)	0.39	2.21	(82)
Transportation	(516)	(610)	(15)	(1.07)	(1.19)	(10)
Royalties	(2,150)	(3,134)	(31)	(4.46)	(6.11)	(27)
	16,496	16,283	1	34.25	31.72	8
Operating	(6,106)	(5,467)	12	(12.68)	(10.65)	19
Well workover expense	(803)	(100)	703	(1.67)	(0.19)	779
Operating netback(2)	9,587	10,716	(11)	19.90	20.88	(5)
Exploration	(370)	(199)	86	(0.77)	(0.39)	97
General and administrative	(5,830)	(5,710)	2	(12.10)	(11.12)	9
Foreign exchange gains	767	580	32	1.59	1.13	41
Interest and other income	59	280	(79)	0.12	0.55	(78)
Interest	(1,584)	(551)	187	(3.29)	(1.07)	207
Bad debt expense	-	(915)	-	-	(1.78)	-
Asset retirement expenditures	(846)	(35)	-	(1.76)	(0.07)	-
Part VI.1 tax on preferred share dividends	(120)	(386)	-	(0.25)	(0.75)	-
Cash flow from operations(1,2)	1,663	3,780	(56)	3.44	7.38	(53)
Changes in non-cash working capital	1,089	(4,985)	122	2.26	(9.71)	123
Cash from by operating activities (1)	2,752	(1,205)	328	5.70	(2.33)	345

(1) Table includes both continuing and discontinued operations.
(2) Non-IFRS measure.

For the six months ended June 30, 2011, cash flow from operations was $1.7 million compared to $3.8 million for the same period in 2010. This was a result of higher interest payments associated with short term debt and a lower operating netback. The lower operating netback in 2011 was primarily due to lower realized gain on financial instruments relative to a hedging contract in 2010. Also contributing to a lower operating netback were increased fixed operating costs and additional workovers, partially offset by a decrease in royalties due to prior period adjustments.

Production

	Three months ended June 30 2011	2010	Six months ended June 30 2011	2010
Natural gas (mcf/d)	11,509	13,631	11,941	13,369
Crude oil (bbls/d)	463	462	466	459
Natural gas liquids (bbls/d)	203	158	205	148
Total production (boe/d) (6:1)	2,584	2,892	2,661	2,836

For the three months ended June 30, 2011 production averaged 2,584 boe per day and for the six months ended June 30, 2011 production averaged 2,661. The decrease from 2010 is mainly due to normal declines in natural gas production, the temporary shutdown of SemCAM's Kaybob South #3 gas plant causing reduced gas revenue for March 2011, and severe weather conditions in the month of May 2011 that prevented access to shut-in wells. Natural gas liquid production increased due to successful workover activity. Oil production increased in the six months ended June 30, 2011 due to a newly tied in well that came onstream in early 2011.

Petroleum and natural gas sales

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
($ thousands, except where otherwise noted)				
Petroleum and natural gas sales				
Natural gas	4,087	4,744	8,694	11,189
Crude oil	4,191	2,947	7,723	6,102
Natural gas liquids	1,321	1,029	2,559	1,603
Transportation	(257)	(333)	(516)	(610)
Royalties	(1,705)	(1,628)	(2,150)	(3,134)
Realized gain on commodity derivatives	110	923	186	1,133
Total	7,747	7,682	16,496	16,283
Average sales price				
Natural gas ($/mcf)	4.09	4.57	4.16	5.09
Crude oil ($/bbl)	97.35	70.13	90.32	73.43
Natural gas liquids ($/bbl)	71.35	72.83	68.61	58.78
Average sales price ($/boe)	41.29	36.64	39.78	39.02

For the three months ended June 30, 2011, petroleum and natural gas sales, net of transportation and royalties was $7.7 million, consisting of $4.1 million in natural gas, $0.1 million in realized gains on commodity derivatives, $4.2 million in crude oil and $1.3 million in natural gas liquids sales, less $1.7 million of royalties and $0.3 million of transportation costs. The Company realized an average sales price of $41.29 per boe during the three months ended June 30, 2011 compared to $36.64 per boe for the same period in 2010, exclusive of royalties and transportation.

For the six months ended June 30, 2011, petroleum and natural gas sales, net of transportation and royalties was $16.5 million, consisting of $8.7 million in natural gas, $0.2 million in realized gains on commodity derivatives, $7.7 million in crude oil and $2.6 million in natural gas liquids sales, less $2.2 million of royalties and $0.5 million of transportation costs. The Company realized an average sales price of $39.78 per boe during the six months ended June 30, 2011 compared to $39.02 per boe for the same period in 2010, exclusive of royalties and transportation.

Royalties

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
($ thousands, except where otherwise noted)				
Royalties				
Crown	1,396	1,501	1,871	2,562
Freehold and overriding	309	127	279	579
Total	1,705	1,628	2,150	3,134
Royalties per boe ($)	7.25	6.19	4.46	6.11
Average royalty rate (%)	18.0	17.5	11.5	16.1

The Company pays royalties to provincial governments, freehold landowners and overriding royalty owners. Royalties are calculated and paid based on petroleum and natural gas sales net of transportation. Crown royalties on Alberta natural gas production are calculated based on the Alberta Reference Price, which may vary from the Company's realized corporate price, impacting the average royalty rate. In addition, various items impact the average royalty rate paid, such as cost of service credits and other royalty credit programs. Royalties on horizontal gas wells drilled in Alberta in 2011 and beyond generally bear royalties at a maximum of 5% for 18 months or until cumulative production reaches 50,000 boe. Horizontal oil wells generally bear royalties at a maximum of 5% for 18 to 48 months until cumulative production reaches 50,000 boe to 100,000 boe, depending on well depth. The Company anticipates that production from wells drilled in 2011 would qualify for these low royalty rates.

Natural gas and liquids royalties for the three months ended June 30, 2011 were $1.7 million or 18.0% of total petroleum and natural gas sales compared to 17.5% in 2010. Freehold and gross overriding royalties increased in 2011 due to a well that came into production in late 2010 with a very high gross overriding royalty. Crown royalties decreased in 2011 due to a lower annual gas cost allowance adjustment in comparison to 2010.

Royalties for the six months ended June 30, 2011 were $2.2 million or 11.5% of total petroleum and natural gas sales compared to 16.1% in 2010. Royalties decreased due to a lower annual gas cost allowance adjustment and a 2011 first quarter adjustment related to past royalties.

Operating and well workover expense

Combined operating and well workover expenses for the three months ended June 30, 2011 were $3.2 million or $13.62 per boe, compared to $2.7 million or $10.23 per boe for the same period in 2010. Combined expenses for the six months ended June 30, 2011 were $6.9 million or $14.35 per boe, compared to $5.6 million or $10.84 per boe for the same period in 2010. The increase from 2010 to 2011 is attributable to additional workovers performed, higher fixed labor costs from increased field staff and increased chemical use due to colder weather.

General and administrative expenses

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
($ thousands, except where otherwise noted)				
Continuing operations				
Gross general and administrative expense	2,867	3,359	6,145	6,126
Capitalized general and administrative expense	(722)	--	(1,758)	(416)
	2,145	3,359	4,387	5,710
Discontinued operations				
Gross general and administrative expense	408	4,302	1,443	7,645
Capitalized general and administrative expense	--	(4,302)	--	(7,645)
	408	--	1,443	--
Total net general and administrative expense	2,553	3,359	5,830	5,710
General and administrative expense ($/boe)	10.86	12.76	12.10	11.12

Continuing operations

For the three months ended June 30, 2011, gross general and administrative ("G&A") expenses for continuing operations decreased to $2.9 million from $3.4 million for the same period in 2010. Gross G&A for continuing operations consists of $0.4 million (2010 – $0.1 million) relating to North Africa and $2.5 million (2010 – $3.3 million) related to Western Canada administration and corporate head office. The decrease is mainly due to legal fees incurred in 2010 associated with corporate litigation.

For the six months ended June 30, 2011, gross general and administrative ("G&A") expenses for continuing operations remained at $6.1 million, which is consistent with the same period in 2010. Gross G&A for continuing operations consists of $1.2 million (2010 – $0.3 million) relating to North Africa and $5.0 million (2010 – $5.8 million) related to Western Canada administration and corporate head office. The increase is mainly due to increased activity in the North Africa office associated with the drilling of the Zarat-1 North well, partially offset by a decrease in legal fees related to corporate litigation in 2010.

Discontinued operations

For the three and six month periods ended June 30, 2011, gross G&A expenses from discontinued operations decreased to $0.4 million and $1.4 million from $4.3 million and $7.7 million respectively in 2010. Costs declined due to a reduction of activity in Trinidad and Tobago pending the sale of those assets and the sale of the LNG Project. On February 22, 2011, the Company completed the sale of the LNG Project to West Face Capital Inc. ("West Face"). The sale of the LNG Project was initiated with West Face in keeping with the Company's strategy of focusing on the development of its interests in Western Canada and North Africa. Pursuant to the sale, the Company received US$1.0 million for reimbursable costs between January 1, 2011 and February 22, 2011, which was recorded as an offset to G&A expenses from discontinued operations. The Company is entitled to receive deferred cash consideration of US$12.5 million payable upon West Face's first successful gas delivery. No amounts have been recorded in the consolidated financial statements related to this contingent consideration. In 2010, net G&A expenses from discontinued operations were lower due the Trinidad and Tobago assets and the LNG Project meeting the criteria for capitalization under IFRS.

Stock based compensation

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Equity based stock option expense	757	476	2,446	901
Liability based stock option expense	212	--	212	--
Stock unit award expense	339	85	780	152
Restricted share unit expense	361	--	361	--
Stock based compensation	1,669	561	3,799	1,053

During the three months ended June 30, 2011, the Company incurred stock based compensation expenses of $1.7 million compared to $0.6 million in 2010. The increase is primarily due to the issuance of new options during the quarter, an increase to the liability associated with existing and newly issued stock unit awards, and issuances under the Company's Restricted Share Unit ("RSU") program. The RSU Plan ("the Plan") became effective on March 24, 2011 to attract and retain experienced personnel with incentive compensation tied to shareholder return. Under the Plan, each grantee will be entitled to, in respect of each RSU, a cash amount equal to the fair market value of one common share in the capital of the Company on such vesting date, with the vesting subject to a minimum floor share price.

Prior to the conversion to IFRS, stock based compensation related to stock options was expensed on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate.

As at June 30, 2011 the Company had issued 1.3 million (December 31, 2010 – 0.7 million) stock unit awards to the Company's executive officers and Board of Directors. A stock unit is the right to receive a cash amount equal to the fair market value of one common share of the Company. The stock units have time and share based performance vesting terms which vary depending on whether the holder is an executive officer or director. If subsequent to the grant date, the shareholders of the Company approve an equity compensation plan under which the stock units may be paid with common shares of the Company, then the Board may determine that the units may be paid in cash or common shares. As of June 30, 2011, the Company recorded a liability of $1.3 million to recognize the fair value of the vested stock units (December 31, 2010 - $1.0 million).

Income taxes

The Company's current and future income taxes are dependent on factors such as production, commodity prices and tax classification of drilling costs related to exploration and development wells.

	June 30, 2011	December 31, 2010
($ millions)		
Non capital losses	103	111
Canadian exploration expense	68	58
Canadian oil and gas property expense	53	40
Canadian development expense	15	15
Undepreciated capital costs	23	23
Share issue costs	1	1
Foreign exploration expense	86	87
Total	349	335

At June 30, 2011, the Company has estimated $349 million in tax pools and non capital losses.that are available for future deduction against taxable income. Non capital losses of approximately $103.0 million included in the total expire after 2027.

Capital expenditures

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
($ thousands)				
Acquisitions	--	--	--	660
Exploration and evaluation	2,218	2,455	10,345	2,890
Drilling and completions	5,513	1,088	7,205	4,416
Plants, facilities and pipelines	807	669	2,187	1,020
Land and lease	1,456	241	1,628	509
Capital well workovers	75	--	133	--
Capitalized general and administrative expenses	722	4,302	1,758	8,061
Capital expenditures	10,791	8,755	23,256	17,556
Trinidad Disposition	(68,611)	--	(88,210)	--
Land and lease impairment, charged to exploration expense	(215)	(41)	(358)	(199)
Net capital expenditures	(58,035)	8,714	(65,312)	17,357

	2011	2010	2011	2010
($ thousands)				
Continuing operations				
Canada	7,674	2,233	10,715	7,014
North Africa	1,979	2,193	10,956	2,393
Corporate Assets	278	54	637	43
	9,931	4,480	22,308	9,450
Discontinued operations				
Trinidad and Tobago	(67,966)	614	(87,620)	1,215
United States (LNG Project)	--	3,620	--	6,692
	(67,966)	4,234	(87,620)	7,907
Net capital expenditures	(58,035)	8,714	(65,312)	17,357

Continuing operations

Western Canada

In the six months ended June 30, 2011, three wells were drilled in Western Canada in the Drumheller Mannville “I” pool. Sonde 3-4 was completed and began producing prior to June 30, 2011 at a total completed cost of $5.2 million, approximately $1.6 million over Authority For Expenditure (“AFE”) due entirely to cost-overruns associated with the hydraulic fracture program. Sonde 3-5 was completed in late July with a total completed cost of $3.3 million, approximately $0.3 million under AFE. The Company also continued its well re-activation program concentrated on an extensive portfolio of suspended wells. The Company performed six gross (4.7 net) new-zone re-entries and 18 gross (15.0 net) work-overs.

North Africa

During the six months ended June 2011, the Company incurred $11.0 million in North Africa on costs related to the drilling and testing of the successful Zarat-1 North appraisal well. The Company commenced drilling in November 2010 and completed drilling and production testing of the appraisal well on the Zarat discovery extension in January

2011. The Company has abandoned the appraisal well in a manner allowing it to be utilized for future development purposes. The Company is currently evaluating the reservoir characteristics and development options. All offshore activities have been suspended pending resolution of the Libyan sanctions and the declaration of force majeure.

Discontinued operations

Trinidad and Tobago

During the six months ended June 30, 2011, the Company incurred $0.6 million related to continued joint venture transactions with the operator of Block 5(c). On December 22, 2010 the Company entered into an agreement to sell its remaining 25% interest in Block 5(c) and the Mayaro-Guayaguayare block ("MG Block") exploration and production license for an aggregate purchase price of US$87.5 million plus interest on the outstanding balance prior to closing. The transaction closed on June 22, 2011 for gross proceeds of US$78.1 million and the assumption of the Company's performance guarantee provided for the MG Block of US$12.0 million. The purchaser legally guaranteed the performance guarantee, resulting in a receivable with the legal right to offset the Company's obligation regarding the MG Block. The Company has recorded this as a receivable offsetting the MG block performance guarantee liability. The Trinidad and Tobago assets and the LNG Project were designated as held for sale at December 31, 2010, meaning general and administrative costs incurred in 2011 no longer met the criteria for capitalization.

Proceeds from disposition	(CDN$ thousands)
Cash received	56,596
Debenture retired	19,898
MG Block Performance Guarantee Assumed by Purchaser	11,716
Transaction costs	(595)
Net proceeds	87,615

Net assets disposed at carrying value	
Exploration and evaluation assets	79,690
Asset retirement obligation	(3,040)
Net assets	76,650
Gross gain on disposition	10,965
Realized foreign currency translation reserve	(5,976)
Net gain on disposition	4,989

Depletion and depreciation

For the three months ended June 30, 2011 depletion and depreciation was $3.0 million or $12.59 per boe compared to $4.4 million or $16.58 per boe for the same period in 2010. The calculation of depletion and depreciation included an estimated $21.5 million (June 30, 2010 - $11.2 million) for future development capital associated with proved plus probable undeveloped reserves and excluded $62.2 million (June 30, 2010 – $15.5 million) related to exploration and evaluation assets. For the six months ended June 30, 2011 depletion and depreciation was $6.2 million or $12.96 per boe compared to $8.7 million or $17.03 per boe for the same period in 2010. The variance for both the three and six months is caused by a higher reserve base in 2011 as a result of reserve additions from 2010, higher estimated future development costs as a result of a revised development plan, and a lower depletion base due to asset impairments in the second and fourth quarters of 2010.

Liquidity and capital resources

($ thousands)	June 30 2011	December 31 2010
Cash and cash equivalents	40,837	2,649
Restricted cash	19,290	--
Accounts receivable	5,934	7,147
Derivative financial assets	410	--
Prepaid expenses and deposits	1,344	1,686
Assets of discontinued operations	40	100,692
Accounts payable and accrued liabilities	(14,978)	(18,126)
Stock based compensation liability	(1,884)	(530)
Provisions	(12,086)	(12,692)
Derivative financial liabilities	(3,452)	(5,099)
Short term debt	(21,365)	(35,048)
Liabilities of discontinued operations	(1,170)	(16,650)
Working capital surplus	12,920	24,029

As at June 30, 2011, the Company had a working capital surplus of $12.9 million (December 31, 2010 – $24.0 million surplus) and had drawn $0.1 million (December 31, 2010 – $20.3 million) against the $40.0 million (December 31, 2010 - $40.0 million) demand revolving credit facility (the "Credit Facility A") at a variable interest rate of prime plus 2.50% (December 31, 2010 – prime plus 0.75%). Credit Facility A is secured by a $100.0 million debenture with a floating charge on the assets of the Company and a general security agreement covering all the assets of the Company. Credit Facility A has covenants, as defined in the Company's credit agreement, that require the Company to maintain its working capital ratio at 1:1 or greater and to ensure that non-domestic G&A expenditures in excess of $7.0 million per year and all foreign capital expenditures are not funded from the Credit Facility A or domestic cash flow while the Credit Facility A is outstanding.

On February 22, 2011, the Company obtained an additional $20.0 million development demand loan ("Credit Facility B") at a variable interest rate of 50 basis points above the variable interest rate on Credit Facility A. Credit Facility B will be used to assist in the acquisition of producing petroleum and natural gas reserves and/or development of proved producing/undeveloped petroleum and natural gas reserves. Subject to availability, review, and the Company's creditor's right of demand, principal and interest shall be repaid over the half-life of the reserves being financed. As at June 30, 2011 the Company has drawn $6.9 million against Credit Facility B.

In April 2011 the Company and its creditor completed their semi-annual review of Credit Facility A and Credit Facility B, resulting in continued approval of both facilities. The Company is subject to the next semi-annual review of its credit facilities on or before October 1, 2011.

As at December 31, 2010, the Company was in violation of one of its debt covenants. This covenant placed a ceiling on foreign expenditures that was exceeded pending the approval of the Trinidad and Tobago asset sale. The Company sought and received a waiver from its lender on this violation and it does not impact the Company's borrowing ability. As at June 30, 2011 the Company was no longer in violation of its debt covenants.

On February 3, 2010, the Company restructured the terms of the Series A, 5.0% US Cumulative Redeemable Convertible Preferred Shares (the "Series A Shares"). Pursuant to the terms of the restructuring, the Series A Shares were exchanged on a share for share basis for 150,000 First Preferred Shares, Series B shares (the "Series B Shares") pursuant to which the redemption date was extended from December 31, 2010 to December 31, 2011, the conversion price was reduced from US$12.50 to US$3.00 and the conversion of 150,000 preferred shares into common shares was increased from 1,200,000 to 5,000,000. The terms of the dividend payment under the Series B Shares remain unchanged from the Series A Shares whereby the Company can elect to pay the quarterly dividend by way of issuance of common shares at market, based on a 5.75% annualized dividend rate in lieu of the 5.0% annualized cash dividend rate. The dividend rate shall be increased by 1/30 of 1% per day restricted to the 150 day period after December 31, 2010 resulting in a maximum applicable annual dividend rate of 6.25% and thereafter reverts to 5%. In addition, the Company granted 500,000 common share purchase warrants exercisable at a price of US$3.25 for each common share and expiring December 31, 2011. The Series B Shares are redeemable by the Company on or after December 31, 2011 and retractable by the Series B Shareholders on December 31, 2011. The

Company can force conversion of the Series B Shares at anytime in the future if its common shares close at a price of at least a 100% premium to the conversion price of US$3.00 on a major US exchange for 20 out of any 30 consecutive trading days while the common shares underlying the Series B Shares are registered. The extension provided the Company with additional flexibility as the Company continues to advance its domestic and international capital programs and work towards improving its liquidity and capital resources. $14.4 million of the Series B shares are reflected in short term debt, June 30, 2011 (December 31, 2010 – $14.8 million).

At June 30, 2011, the Company had $40.8 million in cash and cash equivalents (December 31, 2010 - $2.6 million) and $19.3 million classified as restricted cash (December 31, 2010 – $19.9 million). The Company generally relies on a combination of cash flow from operations and credit facility to fund its capital requirements and to provide liquidity for domestic and international operations.

The Company’s cash flow from operations is directly related to underlying commodity prices and production volumes. A significant decrease in commodity prices could materially impact the Company's future cash flow from operations and liquidity. In addition, a substantial decrease in commodity prices could impact the Company’s borrowing base under its credit facilities, therefore reducing funds available for Western Canada investment, and in some instances, requiring a portion of the credit facilities to be repaid. The Company has entered into risk management contracts to mitigate commodity prices. Management continues to review various other risk mitigating options.

Contingencies and commitments

Block 5(c) Trinidad and Tobago

At June 30, 2011, BG International Ltd. (“BG”) held in escrow for the Company US$20.0 million whereby the Company must maintain the lesser of US$20.0 million or 25% of the estimated capital expenditure requirements in respect of Block 5(c) through to the end of the second phase of the exploration period. Any draws made against the US$20.0 million are required to be replenished by the Company within 30 days of the draw date. Upon closing of the sale agreement of Block 5(c), the Company was eligible to reclaim US$20.0 million ($19.3 million in Canadian dollars) held as restricted cash with BG International Limited (“BG”) that was required under the Companies’ Creditor Arrangement Act Plan of Arrangement. On August 4, 2011 the Company received payment of the US$20.0 million.

MG Block Trinidad and Tobago

In 2007, the Company received an exploration and development license from the Government of Trinidad and Tobago on the MG Block and as a result was committed to conducting 3D seismic by the end of 2009 and to drill two exploration wells on the MG block in a joint venture with The Petroleum Company of Trinidad and Tobago Limited (“Petrotrin”). The first well had to be drilled to a depth of at least 3,000 meters by January 2010 and the second to a depth of at least 1,800 meters by July 2010. The Company agreed to provide a performance security to Petrotrin of US$12.0 million to meet the minimum work program.

The Company’s agreement to sell its remaining interest in Block 5(c) and the MG Block includes the assumption of the performance guarantee. Upon closing the sale on June 22, 2011 the purchaser assumed the performance guarantee for the MG Block. While the rights to the MG Block were not transferred to the purchaser, this guarantee provides a receivable with the legal right to offset the US$12.0 million performance guarantee in discontinued operations. Should the Company be required to pay the performance security amount in order to relinquish the MG Block, the purchaser will reimburse the Company for any amounts owing up to US$12.0 million. The Company expects that purchaser’s guarantee will offset any further liability with respect to MG Block. As of June 30, 2011, the Company was in the process of ceasing all operations in Trinidad and exiting the country.

North Africa

7th of November block

On August 27, 2008, the Company entered into the 7th of November Block Exploration and Production Sharing Agreement ("EPSA") with a Tunisian/Libyan company, Joint Exploration, Production, and Petroleum Services Company ("Joint Oil"). The EPSA contract area straddles the offshore border between Tunisia and Libya. Under terms of the EPSA, the Company has been named operator. Under the EPSA, the minimum work program for the first phase (four years) of the seven year exploration period includes the Zarat North-1 appraisal well, three exploration wells and 500 square miles of 3D seismic. The EPSA provides for penalties for non-fulfillment of the minimum work program of US$15.0 million per exploration well and up to US$4.0 million for 3D seismic not completed. The Company has provided a corporate security to a maximum of US$49.0 million to secure its minimum work program obligations. On January 11, 2011, the Company announced the successful drilling and production testing of its 100% working interest in the Zarat North–1 well. The well has been temporarily abandoned in a manner allowing it to be utilized for future development purposes while the Company evaluates reservoir characteristics and development options on a field development.

Political issues and Libyan sanctions

The governments of Tunisia and Libya are in political turmoil. During January 2011, protests in Tunisia led to the overthrow of the government. The Company safely evacuated its personnel and the rig and equipment without incident. Election of a new national constituent assembly is scheduled to take place later this year. While relative calm has been restored, uncertainty remains over the future direction of the country. Similarly, widespread protests over the government in Libya have occurred and a state of war exists between government and opposition forces. This has led to the cessation of oil production in the country and military intervention by Western forces. On February 26, 2011, the United Nations imposed sanctions on the Libyan government followed by consequent actions of the Canadian Government pursuant to the Special Economics Measures Act (Canada) (the “Libyan Sanctions”). While this turmoil has not had a direct impact on the Company’s 7th of November Block evaluation of the Zarat North-1 results and planning of future activities, it may significantly and adversely affect the Company in various ways, including the functioning of Joint Oil, the pace of future development plans and activities, the ability to secure supplies and personnel, the ability to make payments to Joint Oil and the ability to attract joint venture partners or financing.

All of the activity related to this concession will be monitored by the Company to ascertain the impact of the turmoil in Tunisia and Libya and the impact, if any, of the Libyan Sanctions. The imposition of sanctions and the state of war are unforeseen circumstances beyond the control of the Company, which render the performance of Sonde’s obligations impossible and thus constitute a condition of Force Majeure. As a result, the Company made a formal Force Majeure declaration to Joint Oil for the 7th of November Block on June 7, 2011. This declaration effectively puts the term of the EPSA on hold, without penalty, pending the resolution of political sanctions and instability in Libya. Joint Oil has questioned the Company’s declaration of Force Majeure and requested that the Company continue to perform under the EPSA. The Company believes that the declaration of Force Majeure is sound and, if challenged, will be upheld.

Swap agreement

At the time it entered into the EPSA, the Company also signed a "Swap Agreement" awarding an overriding royalty interest and optional participating interest to Joint Oil, in the Company's "Mariner" Block, offshore Nova Scotia, Canada. If at the end of August 2011, no well has been drilled on the Mariner Block, Joint Oil has the right to put back and sell the overriding royalty to the Company for US$12.5 million. On December 31, 2010, the Mariner Block license lapsed resulting in the Company no longer holding any interest in offshore Nova Scotia, Canada. As a result, Joint Oil would be eligible to exercise its option on or after August 27, 2011. The June 7, 2011 Force Majeure declaration was applied to this Swap Agreement. The Libyan Sanctions prohibit the Company from honoring the option.

Litigation and claims

In December 2009, a class action lawsuit was commenced in the United States District Court of the Southern District of New York against certain former executive officers of the Company for allegedly violating the United States Securities and Exchange Act of 1934 by failing to disclose information concerning its prospects in Trinidad and Tobago. In addition, in May and June 2010, two proposed class action lawsuits were commenced in the Ontario Superior Court of Justice. The actions are made against different groups of former executives and directors of the Company. One of the actions alleges oppression and improper option granting practices and includes the Company and Challenger, a wholly owned subsidiary of the Company, as defendants. The actions contain various claims relating to allegations of misrepresentation and failure to disclose information concerning the Company's activities in Trinidad and Tobago. The class action lawsuits purport to be brought on behalf of purchasers of common shares of the Company from January 14, 2008 to February 17, 2009.

On October 25, 2010, a memorandum of understanding ("MOU") was entered into whereby the parties to the class action lawsuits and the former executive officers agreed to settle the Litigation upon the terms and conditions set forth in the MOU, subject to court approval and all other conditions to the settlement to be mutually agreed upon in a final stipulation of settlement (the "Stipulation").

Under the terms of the MOU, the parties have agreed that the Stipulation will provide, among other things, for the full and final disposition of the Litigation, with prejudice and without costs, by the establishment of a US$5.2 million settlement fund by the Defendants' insurers for the benefit of a settlement class which shall consist of all those who purchased securities of the Company between January 14, 2008 and February 17, 2009. Pending the negotiation and execution of the Stipulation, the parties to the Litigation will ask the presiding courts to continue the stay of all proceedings in the Litigation, except as necessary to consummate the settlement. While the Company believes that the stipulation will ultimately be consummated, no assurance can be provided.

The Defendants continue to deny any and all liability under securities laws and that they committed any violations of law or engaged in any wrongful acts, and that the settlement is being agreed to in order to eliminate the burden and expense of further litigation.

In addition, the Company may be involved in various claims and litigation arising in the ordinary course of business. In the opinion of the Company the various claims and litigations arising there from are not expected to have a material adverse effect on the Company's financial position or its results of operations. The Company maintains insurance, which in the opinion of the Company, is in place to address any unforeseen claims.

Changes to Board of Directors

Effective April 5, 2011 Mr. W. Gordon Lancaster, CA, was appointed to the Company's Board of Directors and was re-elected at the Company's Annual and Special Meeting of shareholders. In addition, the Board appointed Mr. Lancaster as Chair of the Audit Committee.

Off-balance sheet arrangements

The Company has no off-balance sheet arrangements.

Share capital

As at August 11, 2011, the Company had 62.3 million common shares, 3.2 million stock options, 0.2 million Series B Preferred Shares and 0.5 million common share purchase warrants issued and outstanding.

Risk Management

In order to manage the Company's exposure to credit risk, foreign exchange risk, interest rate and commodity price risk, the Company developed a risk management policy. Under this policy, it may enter into agreements, including fixed price, forward price, physical purchases and sales, futures, currency swaps, financial swaps, option collars and put options. The Company's Board of Directors evaluates and approves the need to enter into such arrangements.

Interest rate risk

The Company is exposed to interest rate risk as the credit facilities bear interest at floating market interest rates. The Company has no interest rate swaps or hedges to mitigate interest rate risk at June 30, 2011. The Company's exposure to fluctuations in interest expense on its net loss and comprehensive loss, assuming reasonably possible changes in the variable interest rate of +/- 1% is $0.1 million. This analysis assumes all other variables remain constant.

Credit risk

Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. The Company mitigates risk from joint venture partners by obtaining partner approval of capital expenditures prior to starting a project.

The Company's accounts receivable are with natural gas and liquids marketers, the Government of the Republic of Trinidad and Tobago and joint venture partners in the petroleum and natural gas business under substantially normal industry sale and payment terms and are subject to normal credit risks. The Company's credit risk exposure is as follows:

	June 30 2011	December 31 2010
(CDN$ thousands)		
Western Canada joint interest billings	210	3,212
Goods and Service Tax receivable	1,461	139
North Africa recoverable expenses	121	--
Revenue accruals and other receivables	4,142	3,796
Accounts receivable included in assets of discontinued operations	14	--
Loans and receivables	5,948	7,147
Cash and cash equivalents	40,837	2,649
Restricted cash	19,290	19,892
Financial assets designated at fair value through profit or loss	410	--
Credit exposure	66,485	29,688

The Company's allowance for doubtful accounts is currently $2.1 million (December 31, 2010 - $3.0 million). These amounts offset $1.8 million in value added tax receivable from the Government of the Republic of Trinidad and Tobago (December 31, 2010 – $1.8 million), $0.3 million of Western Canada joint interest and miscellaneous receivables (December 31, 2010 – $0.3 million) and nil withholding tax receivable on preferred share dividends (December 31, 2010 – $0.9 million) that the Company considers past due.

Commodity price risk

The Company enters into commodity sales agreements and certain derivative financial instruments to reduce its exposure to commodity price volatility. These financial instruments are entered into solely for risk mitigation purposes and are not used for trading or other speculative purposes. The following commodity price risk contracts were in place as of the date of this report.

Term	Contract	Volume (GJ/d)	Fixed Price ($/GJ)	Realized gain
March 1, 2011 – December 31, 2011	Swap	5,000	$4.11	$291

In exchange for receiving the fixed price on the February 14, 2011 Swap Agreement, the Company issued the following call option:

Term	Contract	Volume (Bbls/d)	Fixed Price (US$/Bbl)	Realized loss
March 1, 2011 – December 31, 2012	Call option	250	$100.00	($105)

Foreign exchange risk

The Company is exposed to foreign currency fluctuations as oil and gas prices received are referenced to U.S. dollar denominated prices. The Company's foreign exchange risk denominated in U.S. dollars is as follows;

(US$ thousands)	June 30 2011	December 31 2010
Cash and cash equivalents	30,805	1,744
Restricted cash	20,000	20,000
Foreign denominated financial assets	50,805	21,744

(US$ thousands)	June 30 2011	December 31 2010
Block 5(c) payables included in liabilities held for sale	1,169	285
MG Block payables included in liabilities held for sale	--	12,040
North Africa payables	3,596	7,947
Mariner swap provision	12,500	12,500
Convertible preferred shares	14,861	14,878
Conversion feature on convertible preferred shares	2,237	4,720
Derivative liability - warrants	161	355
Foreign denominated financial liabilities	34,524	52,725

These balances are exposed to fluctuations in the U.S. dollar. In addition, the Company is exposed to fluctuations between U.S. dollars and the domestic currencies of Trinidad and Tobago and Tunisia. At this time, the Company has chosen not to enter into any risk management agreements to mitigate foreign exchange risk. The Company's exposure to foreign currency exchange risk on its comprehensive income assuming reasonably possible changes in the U.S. dollar to Canadian dollar foreign currency exchange rate of +/- one cent is $0.6 million. This analysis assumes all other variables remain constant.

Sensitivities

The following sensitivity analysis is provided to demonstrate the impact of changes in commodity prices on first quarter 2011 petroleum and natural gas sales and is based on the balances disclosed in this MD&A and the consolidated financial statements for the three months ended June 30, 2011:

($ thousands)	Petroleum and Natural Gas Sales(1)
Change in average sales price for natural gas by $1.00/mcf	1,047
Change in the average sales price for crude oil and natural gas liquids by $1.00/bbl	61
Change in natural gas production by 1 mmcf/d (2)	372
Change in crude oil and natural gas liquids production by 100 bbls/d (2)	830

(1) Reflects the change in petroleum and natural gas sales for the three months ended June 30, 2011.
(2) Reflects the change in production multiplied by the Company's average sales prices for the three months ended June 30, 2011.

Quarterly financial summary

($ thousands except per share and production amounts)

	2011 IFRS Q2	2011 IFRS Q1	2010 IFRS Q4	2010 IFRS Q3	2010 IFRS Q2	2010 IFRS Q1	2009 CGAAP Q4	2009 CGAAP Q3
Production								
Natural gas (mcf/d)	11,509	12,377	14,140	12,417	13,631	13,104	14,428	11,794
Crude oil and natural gas liquids (bbl/d)	672	677	730	646	620	595	653	582
Total (boe/d)	2,584	2,740	3,087	2,716	2,892	2,779	3,058	2,548
Petroleum & natural gas sales (2)	7,747	8,749	10,002	7,847	7,682	8,601	9,370	5,843
Net income (loss) (1)	2,781	(6,261)	(69,644)	146	(19,988)	(2,697)	(63,903)	29,456
Net income (loss) per share – basic(1)	0.04	(0.10)	(1.12)	0.00	(0.33)	(0.05)	(1.62)	0.85
Cash flow from (used for) operations (3) (4)	423	1,240	(555)	1,086	727	3,054	3,671	(13,133)
Cash flow from (used for) operations per share – basic (3) (4)	0.01	0.02	(0.01)	0.02	0.01	0.05	0.09	(0.38)

(1) This table includes both continuing operations and discontinued operations.
(2) Petroleum and natural gas sales and realized gains on financial instruments net of transportation costs and royalties.
(3) Non-IFRS measures.
(4) Prior period cash flow from (used for) operations has been revised to reflect the impact of foreign exchange on cash and cash equivalents.

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

- Revenue is directly impacted by the Company's ability to replace existing declining production and add incremental production through its on-going capital expenditure program.
- Fluctuations in the Company's petroleum and natural gas sales and net income (loss) from quarter to quarter are primarily caused by variations in production volumes, realized oil and natural gas prices and the related impact of royalties.
- Fluctuations in debt levels from quarter to quarter can substantially impact the company's net income and cash flow from operations.

Please refer to the other sections of this MD&A for the detailed discussions on changes for the three and six months ending June 30, 2011, and to the Company's previously issued interim and annual MD&A for changes in prior quarters.

Disclosure controls and procedures and internal control over financial reporting

Disclosure controls and procedures are designed to provide reasonable assurance that material information is gathered and reported to senior management as appropriate to allow timely decisions regarding public disclosure.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2011 and ending on June 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. Management concluded during the interim period ended June 30, 2011, no material changes in the Company’s internal controls and procedures have occurred during the Company’s most recent interim period, which have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting.

Significant accounting estimates and judgments

The timely preparation of the condensed consolidated financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, those areas discussed below.

Oil and gas reserves and resources

Certain depletion, depreciation, impairment and decommissioning and restoration charges are measured based on the Company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. Reserves and resources have been evaluated at December 31, 2010 by independent petroleum consultants in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering dates, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at each annual reporting date, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Exploration and evaluation costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The Company is required to make estimates and judgments about the future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Unsuccessful drilling, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important factors when making this determination. If a judgment is made that the extraction of resources is not viable, the associated exploration and evaluation costs are impaired and charged to net income or loss.

Decommissioning liabilities and other provisions

The Company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and prices. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented. Other provisions are recognized in the period in which it becomes probable that there will be a future cash outflow.

Deferred income taxes

Deferred tax assets are recognized when it is considered probable that unused tax losses, tax credits and deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the Company's estimate, the ability of the Company to realize the deferred tax asset could be impacted.

Deferred tax liabilities are recognized for taxable temporary differences. The Company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the Company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdiction which the Company operates.

Impairment of assets

The allocation of assets into cash generating units (“CGU’s”) requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

The recoverable amounts of CGU’s and individual assets have been determined based on the higher of fair value less costs to sell. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes and future operating and development costs. Changes to these assumptions will affect the recoverable amounts of CGU’s and individual assets and may then require a material adjustment to their related carrying value.

Share-based payment

Expenses recorded for share-based payments are based on the historical volatility of the Company's share price which may not be indicative of the future volatility. Accordingly, those amounts are subject to measurement uncertainty.

Adoption of IFRS

IFRS transition exemptions

IFRS 1 requires the presentation of comparative information as at the January 1, 2010 transition date and subsequent comparative periods as well as the consistent and retrospective application of IFRS accounting policies. To assist with the transition, the provisions of IFRS 1 allow for certain mandatory exceptions and optional exemptions for first-time adopters to alleviate the retrospective application of all IFRSs. The Company has applied the following exemptions to full retrospective application of IFRS in accordance with IFRS 1:

(i) Deemed cost of property plant and equipment

The Company has elected to apply the exemption under IFRS 1 allowing the measurement of oil and gas assets at the date of transition to IFRS to be determined based on the amounts disclosed under the full cost method of accounting in accordance with Canadian GAAP.

(ii) Decommissioning liabilities

The exemption provided in IFRS 1 from the full retrospective application of IFRS 1 has been applied and the difference between the carrying values of the Company's decommissioning liabilities as measured under IFRS and their carrying values under Canadian GAAP as of January 1, 2010 has been recognized directly in opening deficit.

(iii) Share-based payments

The Company has elected not to apply IFRS 2, Share-based Payments to equity instruments granted after November 7, 2002 that have not vested by the transition date.

(iv) Borrowing costs

The Company has applied the borrowing cost exemption in IFRS 1. It has applied the requirement of IAS 23 to borrowing costs relating to qualifying assets on a prospective basis from the date of transition to IFRS.

(v) Foreign currency translation

The cumulative translation differences for all foreign operations are deemed to be zero at the date of transition to IFRS. Cumulative translation differences are recorded prospectively from this date.

(vi) Business combinations

IFRS 1 allows an entity to use the IFRS rules for business combinations on a prospective basis rather than restating all business combinations.

Mandatory exceptions to retrospective application

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Company under Canadian GAAP are consistent with their application under IFRS.

The remaining IFRS 1 exemptions were not applicable or material to the preparation of the Company's Consolidated Statement of Financial Position at the date of transition on January 1, 2010.

Explanation of significant adjustments

(i) Assets/liabilities held for sale and discontinued operations

Foreign currency translation differences associated with the LNG Project and Trinidad and Tobago assets and liabilities were recorded as part of net loss from discontinued operations under Canadian GAAP. Under IFRS, these differences were reclassified to other comprehensive income. See section (xi) for details on foreign currency translation differences.

Decommissioning provision differences between IFRS and Canadian GAAP associated with Trinidad and Tobago assets were recorded as changes to liabilities held for sale. The impact of changes to the accretion of these provisions was recorded to net loss from discontinued operations. See section (ii) for details on decommissioning provision differences.

(ii) Decommissioning provision

Under Canadian GAAP, increases in the estimated cash flows were discounted using the current credit-adjusted risk-free rate while downward revisions in the estimated cash flows were discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. Under IFRS, estimated cash flows are discounted using the risk-free rate that exists at the statement of financial position date.

In accordance with IFRS 1, the Company elected to re-measure its decommissioning provision at the IFRS transition date and has estimated the related asset by discounting the liability to the date in which the liability arose and recalculated the accumulated depreciation and depletion under IFRS. Adjustments at the IFRS transition date have been recorded to opening deficit. Adjustments arising as a result of changes in the interest rate during the 2010 period have been recorded to property plant, and equipment. The impact of these changes on accretion has been reflected as a change in financing costs.

(iii) Convertible preferred shares

Under Canadian GAAP, the convertible instrument is split into a liability and an equity component. The value of the liability component was determined at the time of placement of the instrument based on the fair value of the debt component of the instrument. The remaining amount was recorded in equity under Canadian GAAP.

The treatment of the liability component determined at the time of placement under IFRS is similar to Canadian GAAP. The initial recognition is at fair value. Under Canadian GAAP the carrying value of the liability component is subsequently accreted to its face value using the effective interest method which is similar to IFRS. No adjustment was required upon adoption of IFRS.

There is no equity instrument recorded for the conversion feature under IFRS. IFRS requires a fixed number of the Company’s own equity instruments to be delivered in exchange for a fixed amount of cash to make recognition as equity possible. As the liability is denominated in United States dollars (“U.S. dollars” or “US$”), and therefore is variable in Canadian dollars, this requirement is not met for the conversion feature of the preferred shares. As a result, under IFRS no equity component can be recorded and the conversion feature is considered an embedded derivative. The embedded derivative is separated and recorded at fair value as a financial derivative liability, with changes in fair value charged to net income or loss.

On December 17, 2009, the Company renegotiated the terms of the convertible preferred shares. Pursuant to the terms of the restructuring, the Series A convertible preferred shares were exchanged for Series B convertible preferred shares and common share purchase warrants. Series A and B shares have different conversion prices and different redemption/retraction dates. The Certificate of Amendment which created the Series B shares was amended February 3, 2010. Under Canadian GAAP, the modification resulted in the Series A shares being presented as non-current at December 31, 2009, despite the redemption/retraction date of the Series A shares being December 31, 2010. Under Canadian GAAP, short term debt that is refinanced with long term debt prior to completion of the statement of financial position can be classified as non-current if certain criteria have been met. Under IFRS the appropriate treatment is to reflect the Series A shares as current liabilities in the IFRS opening statement of financial position.

The equity treatment of the modification under Canadian GAAP resulted in adjustments to contributed surplus and incremental equity on preferred shares. Under IFRS, these adjustments are reversed as the conversion feature of the modified convertible preferred shares are recorded at their fair value.

(iv) Preferred share warrants

As part of the February 3, 2010 modification of the convertible preferred shares, the Company issued warrants, the exercise price of which is denominated in U.S. dollars. Under Canadian GAAP these warrants have been recorded in equity. Under IFRS, the warrants are recorded as a derivative liability at fair value at issuance and at the end of each reporting period, with changes in fair value being recorded in income in the same manner as the convertible preferred shares above.

(v) Exploration and evaluation assets and property plant and equipment

Under Canadian GAAP, the Company applied the full cost method of accounting for oil and gas exploration, development and production activities. Under the full cost method, all costs associated with these activities were capitalized. Under IFRS, the Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

- exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP;

- non-oil and gas assets (corporate assets) were reclassified from the full cost pool to property plant and equipment;

- LNG Project related costs were identified as intangible start-up costs and reclassified from the full cost pool to property plant and equipment; and

- the remaining full cost pool was allocated to the producing/development assets and components pro rata using reserve values.

The Company's exploration and evaluation assets consist of its undeveloped Western Canada land and North Africa offshore assets. Undeveloped land costs identified as exploration and evaluation assets pertain to only those undeveloped sections that the Company intended to actively pursue through its upcoming development programs. Exploration and evaluation assets were assessed for impairment on the IFRS transition date as described in section (vi). Corporate assets and LNG Project costs were also adjusted out of the full cost pool as these were considered non-oil and gas related costs and therefore not subject to the application of the deemed cost exemption. Corporate assets and the LNG Project were evaluated for impairment and subsequently recorded at their carrying values to property plant and equipment.

(vi) Impairments

Under Canadian GAAP, an item of property plant and equipment is deemed recoverable if the undiscounted future cash flows exceed the carrying value of the asset group. Under IFRS, recoverability or property plant and equipment is based on the higher of fair value less costs to sell and value in use of the CGU.

The Company recorded impairments on all of its CGU's within its Western Canada producing and developed assets on the IFRS transition date resulting in an adjustment from property, plant and equipment to opening deficit. During the 2010 comparative period, ceiling test impairments were recognized under Canadian GAAP at June 30, 2010 and December 31, 2010. Under IFRS, the Company evaluated these assets for indicators of impairment at each reporting period resulting in further impairment adjustments recorded at June 30, 2010 and December 31, 2010 in relation to the Company's Western Canada producing and developed assets. Impairments were the results of declining long-term natural gas prices resulting in the carrying value of these CGU's exceeding their recoverable amounts. Recoverable amounts have been determined using fair value less costs to sell and value in use (the net present value of the cash flow or benefit that an asset generates for a specific use) of each CGU.

(vii) Depletion and depreciation

Under IFRS, the Company adopted a policy of depleting its producing and developed oil and gas assets on a unit of production basis over estimated proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. Under Canadian GAAP, depletion was calculated using all of Canada as a single cost centre. IFRS requires depletion and depreciation to be calculated based on individual components (ie. fields or combinations thereof) or CGU's.

(viii) Exploration costs and other income

Under Canadian GAAP, all exploration costs were capitalized in accordance with the full-cost method of accounting for oil and gas assets. Exploration costs identified under IFRS include those costs associated with leases and licences related to undeveloped land that are no longer being actively pursued by the Company as part of its development program. These costs have been recorded as an adjustment from property, plant and equipment to exploration costs during 2010.

IFRS adjustments related to other income relate to a refund of Nova Scotia offshore work deposits that were recorded against property, plant and equipment under Canadian GAAP during 2010. Under IFRS, carrying value associated with Nova Scotia offshore leases were impaired as part of the application of deemed cost under IFRS 1 on the IFRS transition date. These refunds have been adjusted from property plant and equipment to other income during 2010.

(ix) Provisions

Under IFRS, onerous contracts arise when the costs of meeting the obligations of a contract exceed the benefits to be derived from the agreement. When an onerous contract arises, IFRS requires that a provision be set up for the present obligation of the contract. The Company has lease agreements for office space which it no longer uses, resulting in costs of the agreements outweighing its benefits. Under IFRS, the leases are considered onerous in which case a provision has been recorded on the IFRS transition date as an adjustment to retained earnings. During 2010, the change in provision is recorded as a reduction against general and administrative expense.

(x) Share-based payments

Under Canadian GAAP, the Company recognized an expense related to share based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiplier. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate.

(xi) Foreign currency translation

IFRS 1 allows companies to deem the cumulative translation difference to be zero at transition date. The gain or loss on a subsequent disposal of any foreign operation then excludes the translation differences that arose before the date of transition to IFRS. The Company has elected to apply this exemption.

When an entity elects to use a deemed cost exemption for certain assets on initial adoption of IFRS, it calculates the cumulative translation amount for those assets not from the date of acquisition but from the date at which the deemed cost amount is determined. The Company has elected to apply the deemed cost exemption for its oil and gas assets as at the date of transition. Therefore oil and gas assets relating to foreign operations identified with a functional currency U.S. dollars will not be adjusted for foreign exchange differences as the deemed cost has established its reporting currency value. The functional currency carrying value for these assets have been determined by applying the Canadian dollar to U.S. dollar spot rate at the IFRS transition date to the deemed cost amounts.

The financial information for those operations for which the functional currency is concluded to be different from the Company's reporting currency of Canadian dollars is the LNG Project, Trinidad and Tobago and North Africa. The only adjustment required at the IFRS transition date is to the decommissioning provision balance for the Company's Block 5(c) Trinidad and Tobago wells. Foreign exchange adjustments during the 2010 comparative period are required for all non-monetary assets and liabilities. The restatement from functional currency to reporting currency on all assets and liabilities have been recorded in other comprehensive income and accumulated under foreign currency translation reserve.

(xii) Flow-through shares

Under Canadian GAAP, proceeds from flow through shares are recorded to share capital. When the tax benefits have been renounced to the flow-through shareholder, the Company records a reduction in share capital with a corresponding increase in the future income tax liability. Under IFRS, share capital for flow-through shares issued is recorded to share capital at the quoted value of the shares at the date of issuance. The difference between the quoted value and the gross proceeds received on the issuance of the shares is recorded as a liability. The tax cost resulting from deduction renouncements, less any proceeds received in excess of the quoted value of the shares, must be included in the determination of the tax expense. The Company's last issuance of flow-through shares was in 2008 resulting in the difference being applied as an increase to share capital with an offset to opening deficit on the IFRS transition date.

(xii) Correction from previous reporting

In the course of preparing the condensed consolidated financial statements for the three and six months ended June 30, 2011 and 2010, management identified an error in the application of IFRS on initial adoption. The Company had previously recognized an impairment of $8.4 million related to exploration and evaluation assets upon initial adoption of IFRS at January 1, 2010. Management has determined that the timing of this impairment was incorrect and that the assets should have been impaired to exploration expense in the quarter ended December 31, 2010. The impact is that exploration and evaluation assets and shareholder's equity were understated by $8.4 million at both January 1, 2010 and March 31, 2010, while exploration expense was understated by $8.4 million for the year ended December 31, 2010. This has been corrected in the reconciliations from Canadian GAAP to IFRS and on the statement of financial position as at January 1, 2010.

Additional Information

Additional information relating to the Company is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Sonde Resources Corp., Suite 3200, 500 – 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6 and on the Company's website at www.sonderesources.com.

Document 3

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS
FULL CERTIFICATE

I, Jack W. Schanck, the Chief Executive Officer of Sonde Resources Corp., certify the following:

1. Review: I have reviewed the interim financial report and interim MD&A (together, the “interim filings”) of Sonde Resources Corp. (the “issuer”) for the interim period ended June 30, 2011.

2. No misrepresentations: Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. Fair presentation: Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. Responsibility: The issuer’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings, for the issuer.

5. Design: Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer’s other certifying officer and I have, as at the end of the period covered by the interim filings

   A. designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      I. material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

      II. information required to be disclosed by the issuer 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 periods specified in securities legislation; and

   B. designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer’s GAAP.

5.1 Control framework: The control framework the issuer’s other certifying officer and I used to design the issuer’s ICFR is the Internal Control over Financial Reporting - Guidance for Smaller Public Companies published by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

5.2 N/A

5. N/A
3

6. Reporting changes in ICFR: The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on April 1, 2011 and ended on June 30, 2011 that has materially affected, or reasonably likely to materially affect, the issuer's ICFR.

Date: August 11, 2011

(Signed) Jack W. Schanck__
Jack W. Schanck
Chief Executive Officer
Sonde Resources Corp.

Document 4

FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS
FULL CERTIFICATE

I, Kurt A. Nelson, the Chief Financial Officer of Sonde Resources Corp., certify the following:

1. Review: I have reviewed the interim financial report and interim MD&A (together, the "interim filings") of Sonde Resources Corp. (the "issuer") for the interim period ended June 30, 2011.

2. No misrepresentations: Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.

3. Fair presentation: Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.

4. Responsibility: The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, for the issuer.

5. Design: Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer and I have, as at the end of the period covered by the interim filings

   A. designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that

      I. material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and

      II. information required to be disclosed by the issuer 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 periods specified in securities legislation; and

   B. designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP.

5.1 Control framework: The control framework the issuer's other certifying officer and I used to design the issuer's ICFR is the Internal Control over Financial Reporting - Guidance for Smaller Public Companies published by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

5.2 N/A

5. 3 N/A

6. Reporting changes in ICFR: The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on April 1, 2011 and ended on June 30, 2011 that has materially affected, or reasonably likely to materially affect, the issuer's ICFR.

Date: August 11, 2011

(Signed) Kurt A, Nelson___
Kurt A. Nelson
Chief Financial Officer
Sonde Resources Corp.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SONDE RESOURCES CORP.
(Registrant)

Date:	August 11, 2011	By:	/s/ K. Nelson	
			Name:	Kurt Nelson
			Title:	Chief Financial Officer