Q3 INTERIM REPORT FOR THE QUARTER ENDED DECEMBER 31, 2011

NIKO REPORTS RESULTS FOR THE QUARTER ENDED DECEMBER 31, 2011

Niko Resources Ltd. ("Niko" or the "Company") is pleased to report its financial and operating results, including consolidated financial statements and notes thereto, as well as its managements' discussion and analysis, for the three and nine month periods ended December 31, 2011. The operating results are effective February 8, 2012. All amounts are in U.S. dollars unless otherwise indicated and all amounts are reported using International Financial Reporting Standards unless otherwise indicated.

PRESIDENT'S MESSAGE TO THE SHAREHOLDERS

Indonesia expansion continued with four blocks being added during the quarter. The Company's net acreage in Indonesia is now about fifteen times greater than its India acreage. Niko now has an interest in twenty deepwater blocks and intends to continue to add additional prospective blocks by applying the science of SeaSeep™ technology. This fiscal year the company has completed almost 300,000 square kilometres of new multibeam data and has cored 394 sites with up to 500 additional sites planned. Joint studies are in the process of being obtained over most of the prospective areas. This program almost doubles the original program that underpins the Company's current acreage. In short, Niko's strategy of adding more prospective acreage continues in Indonesia and will extend beyond Indonesia next quarter when the Company plans to use Seaseep™ technology to survey approximately 290,000 square kilometres in five basins along the equatorial margin of Northeastern Brazil extending west to the French Guayana-Brazil border.

At the 5c block in Trinidad, a development plan that is awaiting Government approval is expected to add reserves and produce at a plateau rate of 250 MMcf/d (63 MMcf/d net to Niko). The Stalin-1 offshore well was drilled in the 2ab block. Although numerous encouraging gas shows were encountered the Oligocene reservoir sands were found to be poorly developed at this location. A second well, Shadow-1 is expected to be spudded next quarter and will also target the Oligocene reservoir. Shadow -1 is 17.5 kilometres east of the Stalin location and 4.7 kilometres north of an existing well that had 1,900 feet of gross Oligocene sands. Offshore seismic was completed at the Guayaguayare and NCMA blocks setting the stage for a large drilling campaign during this fiscal year. At the Central Range block the Company is currently completing and testing the Cribo-1 well and the Mapepire-1 well is currently being logged. A third well, Tigre-1 is planned later this year. Acreage expansion also continued in Trinidad with the addition of the MG block where 2D seismic has already been completed. The Company's land base in Trinidad is now larger than its land base in India.

In India, plans were approved for the development of the first four satellite discoveries. In addition, further development is expected at D6 when the "R complex" and three additional satellite discoveries are added.

Edward S. Sampson – President and Chief Executive Officer, Niko Resources Ltd.

FINANCIAL AND OPERATING HIGHLIGHTS

- Total production in the quarter averaged 219 MMcfe/d (235 MMcfe/d year-to-date)
- Operating cash flow in the quarter was $65 million ($222 million year-to-date)
- The Company entered into an agreement for two credit facilities totaling $250 million
- The Company adopted international financial reporting standards (IFRS). Please see note 27 to the consolidated financial statements for a detailed reconciliation of Canadian GAAP to IFRS for results previously reported under Canadian GAAP.
- The loss for the quarter under IFRS was $40 million and includes $57 million of exploration and evaluation costs. The $57 million of expensed exploration and evaluation costs related primarily to seismic costs and while expensed under IFRS, seismic is simply an important prelude to drilling. The loss year-to-date was $139 million and includes $117 million of exploration and evaluation costs (primarily seismic), a $14 million charge related to cancelled options and a $58 million loss related to a change in accounting estimate with respect to deferred income taxes as discussed in detail in "Segment Profit – India – Income Taxes" in the Company's management's discussion and analysis.

EXPLORATION and DEVELOPMENT HIGHLIGHTS

- Indonesia:
  - During the quarter acquisition of 3D seismic was completed for the South Matindok and Sunda Strait I blocks; SeaSeep™ technology continued; and
  - The Company continued gearing up for its drilling campaign.
- Trinidad and Tobago:
  - At the Central Range block, work continued at both the Cribo-1 well and the Mapepire-1 well;
  - At Block 2ab, Niko drilled the Stalin-1 well and began preparing for its second well;
  - During the quarter seismic activity was conducted at the Guayaguayare Block and at both of the NCMA blocks; and
  - The Block 5c development plan is awaiting Government approval.
- India: The development plan was approved for the first four satellite fields.
- Kurdistan: Planning continued for the second well in the Qara Dagh block.
- Looking ahead to Fiscal 2013 the Company forecasts exploration capital spending of approximately $160 million.

REVIEW OF OPERATIONS AND GUIDANCE

Sales Volumes

	Three months ended December 31,		Nine months ended December 31,	
	2010	2011	2010	2011
Oil and condensate production (bbls/d)	2,590	1,679	2,941	1,930
Gas production (Mcf/d)	276,865	209,129	282,821	223,791
Total production (Mcfe/d)	292,402	219,204	300,469	235,368

Natural gas production at the D6 block was 143 MMcf/d during the quarter (157 MMcf/d year-to-date) compared to 195 MMcf/d in the prior year's quarter (204 MMcf/d in the prior year-to-date period). D6 gas production in December averaged approximately 137 MMcf/d. Declines are expected to continue until workovers are completed and/or additional wells are tied-in. Block 9 produced 58 MMcf/d of natural gas in the quarter (58 MMcf/d year-to-date) compared to 71 MMcf/d in the prior year's quarter (65 MMcf/d in the prior year-to-date period). The Bangora-1 well is producing at a consistent level, which is lower than the prior year periods due to a mechanical problem that cannot be remedied in a cost-effective manner. Production from this well is expected to continue at no higher than current levels.

Operating Cashflow

	Three months ended December 31,		Nine months ended December 31,	
	2010	2011	2010	2011
Operating cashflow ($ millions) (1)	89	65	283	222
Operating netback ($/Mcfe)	3.30	3.23	3.43	3.43

(1) Operating cash flow is defined as oil and natural gas revenues less royalties, profit petroleum and the cash-portion of operating expense and is a non-IFRS measure. Operating netback is the operating cash flow per unit of production measured in Mcfe and is a non-IFRS measure.

While operating netback per Mcfe was virtually unchanged at approximately $3.43 per Mcfe in the period, operating cash flow decreased as a result of the decreases in production described above.

Forward-Looking Information and Material Assumptions

This report on results for the three and nine months ended December 31, 2011 contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending.

Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this report on results for the three and nine months ended December 31, 2011 should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in the Company's management's discussion and analysis for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report on results for the three and nine months ended December 31, 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the three and nine months ended December 31, 2011 should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2011. This MD&A is effective February 8, 2012. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

All financial information is presented in thousands of U.S. dollars unless otherwise indicated.

The term "the quarter" is used throughout the MD&A and in all cases refers to the period from October 1, 2011 through December 31, 2011. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from October 1, 2010 through December 31, 2010.

The fiscal year for the Company is the 12-month period ended March 31. The terms "Fiscal 2011" and "prior year" is used throughout this MD&A and in all cases refers to the period from April 1, 2010 through March 31, 2011. The terms "Fiscal 2012", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2011 through March 31, 2012.

Mcfe (thousand cubic feet equivalent) is a measure used throughout the MD&A. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl:6 Mcf. Mcfe may be misleading, particularly if used in isolation. An Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. MMBtu (million British thermal units) is a measure used in the MD&A. It refers to the energy content of natural gas (as well as other fuels) and is used for pricing purposes. One MMBtu is equivalent to 1 Mcfe plus or minus up to 20 percent, depending on the composition and heating value of the natural gas in question.

Less than 2 percent of total corporate production volumes and total corporate revenue are from Canadian oil and Bangladeshi condensate. Therefore, the results from Canadian oil and Bangladeshi condensate production are not discussed separately.

Forward-Looking Information and Material Assumptions

This MD&A contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending. Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this MD&A should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect.

Forward-looking information in this MD&A includes, but is not necessarily limited to, the following:

Forecast production rates: The Company prepares production forecasts taking into account historical and current production, and actual and planned events that are expected to increase or decrease production and production levels indicated in the Company's reserve reports.

Forecast capital spending and commitments: The Company prepares capital spending forecasts based on internal budgets for operated properties, budgets prepared by the Company's joint venture partners, when available, for non-operated properties, field development plans and actual and planned events that are expected to affect the timing or amount of capital spending.

Forecast operating expenses: The Company prepares operating expense forecasts based on historical and current levels of expenses and actual and planned events that are expected to increase or decrease production and/or the associated expenses.

Timing of production increases, timing of commencement of production and timing of capital spending: The Company discloses the nature and timing of expected future events based on the Company's budgets, plans, intentions and expected future events for operated properties. The nature and timing of expected future events for non-operated properties are based on budgets and other communications received from the Company's joint venture partners.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis when the change is material and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in this MD&A for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this MD&A.

Non-IFRS Measures

The selected financial information presented throughout the MD&A is prepared in accordance with International Financial Reporting Standards (IFRS), except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback" and "segment profit", which are used by the Company to analyze the results of operations.

By examining funds from operations, the Company is able to assess its past performance and to help determine its ability to fund future capital projects and investments. Funds from operations is calculated as cash flows from operating activities prior to the change in operating non-cash working capital, the change in long-term accounts receivable and exploration and evaluation costs expensed to the statement of comprehensive income.

By examining operating netback, funds from operations netback, earnings netback and segment profit, the Company is able to evaluate past performance by segment and overall.

Operating netback is calculated as oil and natural gas revenues less royalties, profit petroleum expenses and operating expenses for a given reporting period, per thousand cubic feet equivalent (Mcfe) of production for the same period, and represents the before-tax cash margin for every Mcfe sold.

Funds from operations netback is calculated as the funds from operations per Mcfe and represents the cash margin for every Mcfe sold. Earnings netback is calculated as net income per Mcfe and represents net income for every Mcfe sold.

Segment profit is defined as oil and natural gas revenues less royalties, profit petroleum expenses, production and operating expenses, depletion expense, exploration and evaluation expense and current and deferred income taxes related to each business segment.

The Company defines working capital as current assets less current liabilities and uses working capital as a measure of the Company's ability to fulfill obligations with current assets.

These non-IFRS measures do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other companies.

OVERALL PERFORMANCE

International Financial Reporting Standards

For fiscal periods beginning on or after January 1, 2011, all Canadian publicly accountable enterprises are required to prepare their financial statements using International Financial Reporting Standards (IFRS). Accordingly, the Company has prepared its unaudited consolidated financial statements for the three and nine months ended December 31, 2011, under IFRS and has presented its unaudited consolidated financial statements for the comparative periods, the three and nine months ended December 31, 2010 to comply with IFRS. The financial information presented in this MD&A is derived directly from the Company's financial statements and as such certain comparative information may differ from what was originally prepared by the Company using previous Canadian generally accepted accounting principles. For further information on the Company's transition to IFRS and a reconciliation of the affected financial information for the nine months ended December 31, 2010, please refer to the Company's unaudited consolidated financial statements for the nine months ended December 31, 2011 and 2010 filed on SEDAR at www.sedar.com and available on the Company's website at www.nikoresources.com.

Funds from Operations

	Three months ended December 31,		Nine months ended December 31,	
(thousands of U.S. dollars)	2011	2010	2011	2010
Oil and natural gas revenue	74,789	99,220	249,877	309,689
Other income	6,453	-	6,453	-
Production and operating expenses	(9,632)	(10,365)	(27,720)	(26,584)
General and administrative expenses	(1,529)	(2,113)	(5,544)	(6,275)
Net finance expense	(3,957)	(5,122)	(15,346)	(20,590)
Realized foreign exchange	(1,035)	(2,073)	(4,403)	1,311
Current income tax recovery / (expense)	1,241	105	(3,048)	(1,043)
Minimum alternate tax expense	(6,221)	(9,064)	(19,019)	(31,172)
Funds from operations (1)	60,109	70,588	181,250	225,336

(1) Funds from operations is a non-IFRS measure as defined under "Non-IFRS measures" in this MD&A.

Oil and natural gas revenue has decreased compared to the prior year's periods as a result of a decrease in gas production at the D6 Block and at Block 9.

The Company farm-outs a portion of its interest in various properties in Indonesia. Other income includes the proceeds from the farm-outs in excess of the recorded asset.

Production and operating expenses year-to-date increased at the D6 Block related to maintenance of the onshore terminal and subsea systems.

General and administrative expense decreased primarily due to overhead recoveries from the branch offices.

Net finance expense decreased in the quarter as the result of an adjustment to historical expenses associated with the 36" pipeline at Hazira. Year-to-date, net finance expense also decreased as a result of the repayment of the long-term debt.

There were realized foreign exchange losses in the quarter and year-to-date as a result of the weakening of the Indian-Rupee against the U.S. dollar.

The current income tax recovery relates primarily to the reversal of a tax provision.

The Company currently pays minimum alternate tax based on accounting income for the D6 block. The expense has decreased as a result of decreased accounting income primarily as a result of decreased revenues.

Net Income (Loss)

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Funds from operations (non-IFRS measure)	60,109	70,588	181,250	225,336
Production and operating expenses	(484)	(451)	(1,501)	(1,331)
Depletion expense	(25,975)	(24,733)	(83,601)	(76,407)
Exploration and evaluation expense	(57,340)	(20,574)	(116,610)	(79,551)
Gain / (loss) on short-term investments	2,384	166	(6,184)	(13,504)
Other expenses	(6,384)	(6,590)	(20,356)	(18,533)
Finance expense	(2,076)	(1,777)	(5,826)	(4,038)
Unrealized foreign exchange (loss) / gain	(3,752)	113	(7,627)	519
Deferred income tax (expense)	(6,887)	9,064	(7,071)	31,172
	(40,405)	25,806	(67,526)	63,663
Change in accounting estimate—deferred taxes	-	-	(57,865)	-
Other expenses—impact of option cancellation	-	-	(13,913)	-
Net income (loss)	(40,405)	25,806	(139,304)	63,663

The decrease in funds from operations is described above. Other items affecting the net income (loss) are described below.

The non-cash portion of production and operating expense and other expense included above are largely for share-based compensation (refer to the corporate section of this MD&A for further details).

Although production volumes are lower in the current year periods, depletion expense increased as a result of the revision to the reserve volumes and future costs included in the March 31, 2011 reserve report.

In the prior year's quarter, exploration and evaluation costs included the seismic programs in Indonesia and Trinidad and branch office costs. In the current quarter, exploration and evaluation costs include seismic programs for the Guayaguayare Area, both NCMA blocks and Block 2AB in Trinidad and Sunda Strait I in Indonesia and branch office costs. The prior year-to-date period also includes the seismic program for Madagascar and additional seismic in Indonesia. Exploration and evaluation costs also include annual payments that are specified in the Trinidad PSCs.

The mark-to-market loss or gain on short-term investments also contributed to period-over-period variances.

The non-cash portion of finance expense included above is for the accretion of the decommissioning obligations and accretion of the convertible debentures (refer to the finance expense section in this MD&A for further details).

The Indian Rupee weakened against the U.S. dollar during the current periods. As a result, there was an unrealized foreign exchange loss on revaluing the Indian-rupee based income tax receivable to U.S. dollars.

The deferred income tax expense primarily relates to revaluing the Indian-rupee based tax pools to U.S. dollars and is partially offset by a recovery related to minimum alternate tax (MAT) credit. The Company currently pays MAT for the D6 block and the expense is included in funds from operations. MAT paid can be carried forward for 10 years and deducted against regular income taxes in future years resulting in the tax credit, which is recorded as a recovery against the deferred income tax expense.

The change in accounting estimate is related to deferred income taxes as a result of revising the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. Although the Company does not expect a change of this magnitude to occur in the future, there may be future changes in this estimate as the circumstances and facts surrounding this estimate change.

Stock options were cancelled during the period and accounting rules require immediate expense recognition as if the cancelled options had vested immediately resulting in a $14 million charge to other expenses in the period.

BACKGROUND ON PROPERTIES

Niko Resources Ltd. is engaged in the exploration for and, where successful, the development and production of natural gas and oil in India, Bangladesh, Indonesia, the Kurdistan region of Iraq, Trinidad, Pakistan and Madagascar. The Company has agreements with the governments of these countries for rights to explore for and, if successful, produce natural gas and oil. The Company generally is granted an exploration licence to commence work. The agreements generally involve a number of exploration phases with specified minimum work commitments and the maximum number of years to complete the work. At the end of any exploration phase, the Company has the option of continuing to the next exploration phase and may be required to relinquish a portion of the non-development acreage to the respective government. If a commercial discovery is not made by the end of all the exploration phases, the Company's rights to explore the block generally terminate. In the event of a discovery that is determined to be commercial, the Company prepares a development plan and applies to the government for a petroleum mining licence. The petroleum mining licences are for a specified number of years and may be extended under certain circumstances. During the production phase, the Company is required to pay any royalties specified in the agreements and taxes applicable in the country or as specified in the production sharing contract (PSC). Where the Company is currently producing, the Company pays to the government an increasing share of the profits based on an Investment Multiple (IM) or on production levels plus an IM, or a fixed share of profits, depending on the agreement. The IM is the number of times the Company has recovered its investment in the property from its share of profits from the property. At the end of the life of the field or the mining licence, the field and the assets revert to the government; however, the Company is responsible for the costs of abandonment and restoration.

India

D6 – The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The D6 Block comprised 77 percent of the Company's oil and gas revenue during the quarter. Production of oil from the MA discovery began in September 2008 and production of gas from the Dhirubhai 1 and 3 discoveries in April 2009. The Company has been granted petroleum mining licences for the discoveries expiring in 2028 and 2025, respectively. Oil production is sold on the spot market at a price based on Bonny Light and adjusted for quality. Gas production is sold under long-term gas contracts using a pricing formula approved by the Government of India, which currently results in a price of $4.20/MMBtu net and there is a marketing margin of $0.135/MMBtu earned in addition to the price formula. This equates to a sales price of approximately $3.95/Mcf.

Under the terms of the production sharing contract (PSC) with the Government of India for the D6 block, the Company is required to pay the government a royalty of 5 percent of the well-head value of crude oil and natural gas for the first seven years from the commencement of commercial production in the field and thereafter to pay 10 percent.

In addition, the Company pays a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company pays 10 percent of profits when the IM is less than 1.5; 16 percent between 1.5 and 2; 28 percent between 2 and 2.5; and 85 percent thereafter. As at December 31, 2011, the profit share was 10 percent.

Hazira – The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India. The Hazira Block comprised 5 percent of the Company's oil and gas revenues in the quarter.

The Company has a petroleum mining licence that expires in September 2014, which can be extended. The Company has one significant contract for the sale of gas production from the field expiring in April 2016 at a current price of $4.86/Mcf.

Surat – The Company holds a development area of 24 square kilometres containing the Bheema and NSA shallow natural gas fields. The block comprised 2 percent of the Company's oil and gas revenue in the quarter. The Company has one contract for the sale of gas production at a price of $6.00/ Mcf until March 31, 2013.

NEC-25 – The Company has a 10 percent working interest in the NEC-25 Block, which covers 9,461 square kilometres in the Mahanadi Basin off the east coast of India. The Company has fulfilled the exploration minimum work commitment for the block.

D4 – The Company has a 15 percent interest in the D4 Block, located in the Mahanadi Basin offshore from the east coast of India. The block, which is currently in the exploration phase, encompasses more than 17,000 square kilometres. The work commitment includes seismic work and three exploration wells. Originally, the work commitment was to be completed by September 2009; however, the Government of India approved a blanket extension to December 31, 2010 for this and other deep-water blocks. This and other extensions allow the Company until June of 2013 to drill the three wells. The Company's share of the estimated cost of the remaining work commitment is $10 million.

Cauvery – The Company has a 100 percent working interest and operates the block, which covers 957 square kilometres. The Company has performed the seismic work and drilled four of the five wells required under the first exploration phase. The estimated cost of the remaining work commitment is up to $2 million. Wells drilled to date have been unsuccessful. The Company intends to relinquish the block.

Bangladesh

Block 9 – The Company holds a 60 percent interest in this 6,880-square-kilometre onshore block that encompasses the capital city of Dhaka. Natural gas and condensate production from this field began in May 2006 and comprised 17 percent of the Company's oil and gas revenues for the quarter. As per the PSC, the Company has rights to produce for a period of 25 years and this arrangement is extendable if production continues beyond this period. The Company sells gas under a gas purchase and sales agreement (GPSA) at a current price of $2.34/MMBtu (approximately $2.33/Mcf) for a period up to 25 years.

The Company shares a percentage of the profits from the block with the government, which varies with production and whether or not the Company has recovered its investment. The Company pays to the government 61 percent and 66 percent of profits, respectively, before and after costs are recovered on natural gas production up to 150 MMcf/d. Profits on natural gas are calculated as the minimum of (i) 55 percent of revenue for the period and (ii) revenue less operating and capital costs incurred to date. As at December 31, 2011, the profit share was 61 percent.

Indonesia

The Company holds interests in PSCs for 20 offshore exploration blocks covering 104,443 square kilometres. The chart below indicates the location, award date, the Company's working interest and the size of the block.

Block Name	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Bone Bay	Sulawesi SW	Nov. 2008	45%	4,969
South East Ganal (1)	Makassar Strait	Nov. 2008	100%	4,868
Seram (1)	Seram North	Nov. 2008	55%	4,991
South Matindok (1)	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri (1)	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Papua NW	May 2009	45%	4,991
Kofiau (1)	West Papua	May 2009	100%(2)	5,000
Kumawa	Papua SW	May 2009	45%	5,004
East Bula (1)	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau (1)	Papua W	Nov. 2009	51%(2)	4,926
North Makassar (1)	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV (1)	Papua SW	Nov. 2009	51%(2)	6,389
Cendrawasih Bay II	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III (1)	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV (1)	Papua NW	May 2010	50%	3,904
Sunda Strait I (1)	Sunda Strait	May 2010	100%	6,960
Obi (1)	Papua W	Nov. 2011	51%	8,057
North Ganal	Makasar Strait	Nov. 2011	31%	2,432
Halmahera II	Papua W	Dec. 2011	20%	6,000
South East Seram (1)	Papua SW	Dec. 2011	100%	8,217

(1) Operated by the Company.

(2) The Company has entered into farmout agreements that, subject to government approval, will reduce its working interest to 57.5% for the Kofiau block and 42% in the Obi block. The Company has entered into a farmout agreement for the West Papua IV and Halmahera-Kofiau blocks whereby the farmor has the options to obtain an additional working interest, subject to government approval, that would reduce the Company's working interest to 40%.

All of the blocks are in the first exploration period. The Company has acquired a total of 29,570 kilometres of 2D seismic and 17,081 square kilometres of 3D seismic fulfilling the seismic work commitments. Eleven of the blocks have a single well commitment. The Company has contracted a rig and the drilling program for the Company's operated blocks is expected to commence in 2012. The Company has estimated the costs to fulfill the remaining work commitments at $267 million to be spent at various dates up to December 2014. The Company has received extensions to the initial 3-year exploration period in order to fulfill the well commitments on certain blocks. The Company is required to relinquish a portion of the exploration acreage after the first exploration period.

Kurdistan

The onshore Qara Dagh block covers approximately 846 square kilometres, in the Sulaymaniyah Governorate of the Federal Region of Kurdistan in Iraq. The Company has a 37 percent interest and carries the proportionate cost for the regional government's interest, resulting in a 46 percent cost interest in the block. In August 2011, the Company agreed to pay an additional cost interest related to a partner's cash call commitments. In return, in the event a commercial discovery is made, Niko will receive an amount equal to the net proceeds of sale associated with a 12 percent undivided interest in the block.

The exploration period is for a term of five years and is extendable by two one-year terms. An exploratory well was drilled between May 2010 and October 2011 to a depth of 4,196 metres, which was the maximum depth possible with the drilling equipment. Multiple zones tested, however, not at commercial rates. The Company has left the well in such a condition that it retains the option to re-enter the well at a later date. The Company's share of the estimated remaining costs for the exploration period is $23 million.

Trinidad

The Company holds interests in ten PSCs/license for seven exploration areas and for one development area (Block 5(c)). The chart below indicates the location, PSC date, the Company's working interest and the size of the block.

Exploration Area	Location	Award Date	Working interest	Area (Square Kilometres)
Block 2AB (1)	Offshore	July 2009	35.75%	1,605
Guayaguayare—Shallow Horizon (1)	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare—Deep Horizon (1)	Onshore/Offshore	July 2009	80%	1,190
Central Range—Shallow Horizon	Onshore	Sept. 2008	32.5%	734
Central Range—Deep Horizon	Onshore	Sept. 2008	40%	856
Block 4(b) (1)	Offshore	April 2011	100%	754
NCMA2 (1)	Offshore	April 2011	56%	1,020
NCMA3 (1)	Offshore	April 2011	80%	2,107
Block 5(c)	Offshore	July 2005	25%	324
MG Block	Offshore	July 2007	70%	223

(1) Operated by the Company.

The Company has minimum exploration work commitments for the acquisition or reprocessing of seismic and to drill a total of 15 wells on the blocks. The seismic commitment has been met for Block 2AB, NCMA2, NCMA3 and the MG Block. The offshore seismic commitment has been met and onshore seismic acquisition is underway for the Guayaguayare Area. Two of the commitment wells have been drilled to date. The Stalin-1 well drilled on Block 2AB was unsuccessful and has been abandoned and the Company is currently completing and testing the Cribho-1 well on the Central Range block. A second well on the Central Range, Mapepire 1, is currently being logged. The estimated cost to complete the remaining commitments is $299 million to be spent at various dates up to April 2016.

The Company closed the acquisition of Block 5(c) in June 2011 for a purchase price of $78.1 million. Block 5(c) is located 94 kilometres off the east coast of Trinidad and the development plan is awaiting government approval. The transfer of the Block MG license was also part of an agreement signed by the Company in December 2010.

Madagascar

The Company has a 75 percent working interest in a PSC for a 16,845-square-kilometre block off the west coast of Madagascar with water depths ranging from shallow water to 1,500 metres. The Company completed a 31,944-line kilometre aero-magnetic survey and a 10,000 square kilometre multi-beam survey. A 3,236-square-kilometre 3D survey was completed in July 2010. The 3D seismic will fulfill the Phase II work commitment. The cost of the Phase III work commitment is estimated at $40 million and includes drilling a well. A well location is expected to be selected after seismic interpretation.

Pakistan

The Company has production sharing agreements (PSAs) for four blocks in Pakistan. The blocks are located in the Arabian Sea offshore the city of Karachi and cover a combined area of almost 10,000 square kilometres. The Company has received a one-year extension to the Phase I exploration period, which now ends March 2014. The Company has substantially completed the commitments under this phase through seismic activity. The Company has evaluated the seismic and has selected drilling locations.

Expenditures

	Three months ended December 31, 2011				Nine months ended December 31, 2011			
	Additions to		Expense to		Additions to		Expensed to	
(thousands of U.S. dollars)	E&E[(2)] assets	PP&E[(2)]	P&L[(2)]	Total	E&E[(2)] assets	PP&E[(2)]	P&L[(2)]	Total
Exploration								
India	-	-	604	604	1,060	-	1,146	2,206
Indonesia	5,810	-	20,384	26,194	11,678	-	47,815	59,493
Kurdistan	3,383	-	607	3,990	23,935	-	2,206	26,141
Madagascar	9	-	292	301	9	-	822	831
Pakistan	120	-	1,025	1,145	248	-	1,820	2,068
Trinidad	12,211	-	33,314	45,525	110,108	-	59,628	169,736
Development						-		
India	-	329	-	329		7,512	-	7,512
Bangladesh	-	-	541	541	-	-	933	933
Other								
New ventures/other	-	1,074	573	1,647	-	1,544	2,240	3,784
Total	21,533	1,403	57,340	80,276	147,038	9,056	116,610	272,704

(1) The amounts presented are the Company's share of expenditures. Expenditures include allocated share-based compensation expense, capitalized general and administrative expenses and decommissioning obligations.

(2) E&E means exploration and evaluation, PP&E means property, plant & equipment and P&L means profit and loss. Additions to PP&E excludes changes in capital work-in-progress.

Additions to exploration and evaluation assets in Indonesia were related to activities preparing for the upcoming drilling campaign and for signing bonuses for new blocks. The spending expensed to the profit and loss included seismic for South Matindok and Sunda Strait I, geological studies and evaluation of new venture opportunities.

Spending in Kurdistan of $15 million relates to drilling and testing the Company's first well on the Qara Dagh block. The well has been drilled to a depth of 4,196 metres, the maximum depth possible with current drilling equipment. Multiple zones tested, however not at commercial rates. The Company has left the well in such a condition that it retains the option to re-enter the well at a later date. In August 2011, the Company agreed to pay an additional cost interest related to a partner's cash call commitments ($9 million included in E&E assets). In return, in the event a commercial discovery is made, Niko will receive an amount equal to the net proceeds of sale associated with a 12 percent undivided interest in the block.

Additions to E&E assets in Trinidad include: signing bonuses of $18 million for the signing of production sharing contracts for three additional blocks in Trinidad in April 2011; the purchase of Block 5(c) in June 2011 for a total purchase price of $78 million; and $14 million for drilling wells for Block 2AB and the Central Range.

Seismic costs for the Guayaguayare Area, Block 2AB and both of the NCMA blocks, payments required as per the production sharing contracts and the costs of operating the branch office in Trinidad are expensed to profit and loss.

SEGMENT PROFIT

INDIA

	Three months ended December 31,		Nine months ended December 31,	
(thousands of U.S. dollars)	2011	2010	2011	2010
Natural gas revenue	56,884	76,174	187,242	242,162
Oil and condensate revenue (1)	13,813	18,481	51,466	58,809
Royalties	(3,650)	(4,857)	(12,191)	(16,059)
Profit petroleum	(1,899)	(2,031)	(5,136)	(6,246)
Production and operating expenses	(7,641)	(8,453)	(22,981)	(21,813)
Depletion expense	(22,639)	(21,475)	(74,416)	(67,608)
Exploration and evaluation expenses	(604)	(975)	(1,146)	(2,529)
Current income tax recovery / (expense)	233	(348)	(4,060)	(1,567)
Minimum alternate tax (expense)	(6,221)	(9,064)	(19,019)	(31,172)
Deferred income tax reduction / (expense)	(6,887)	9,064	(7,071)	31,172
Change in accounting estimate—deferred taxes	-	-	(57,865)	-
Segment profit (2)	21,389	56,516	34,823	185,149
Daily natural gas sales (Mcf/d)	150,701	205,428	165,839	217,324
Daily oil and condensate sales (bbls/d) (1)	1,478	2,331	1,728	2,721
Operating costs ($/Mcfe)	0.49	0.34	0.45	0.30
Depletion rate ($/Mcfe)	1.54	1.06	1.54	1.05

(1) Production that is in inventory has not been included in the revenue or cost amounts indicated.

(2) Segment profit is a non-IFRS measure as calculated above.

Segment profit from India includes the results from the Dhirubhai 1 and 3 gas fields and the MA oil field in the D6 Block, the Hazira oil and gas field and the Surat gas field.

Revenue and Royalties

The Company's gas production for the quarter from the D6 block averaged 143 MMcf/d compared to 195 MMcf/d in the prior year's quarter. Year-to-date D6 gas production was 157 MMcf/d compared to 204 MMcf/d in the prior year's period. Declines are expected to continue until workovers are completed and/or additional wells are tied-in. In addition, natural declines are continuing at the Hazira and Surat blocks.

Oil and condensate sales decreased in the current periods compared to the prior year periods. Oil production from the D6 Block decreased as five wells were producing in the periods compared to six wells for the majority of the prior year's periods and a decrease in production from the remaining wells. The decrease as a result of volumes was partially offset by an increase in realized oil price to $101/bbl and $108/bbl in the quarter and year-to-date, respectively, compared to $80/bbl and $79/bbl in the same periods in the prior year.

The decrease in royalties is a result of the decreased revenues described above. Royalties applicable to production from the D6 Block are 5 percent for the first seven years of commercial production and gas royalties applicable to the Hazira and Surat fields are currently 10 percent of the sales price.

Profit Petroleum

Pursuant to the terms of the PSCs the Government of India is entitled to a sliding scale share in the profits once the Company has recovered its investment. Profits are defined as revenue less royalties, operating expenses and capital expenditures. The decrease in profit petroleum is a result of the decreased revenues described above.

For the D6 Block, the Company is able to use up to 90 percent of profits to recover costs. The government was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum during the quarter was $0.6 million, which is one percent of revenues, and will continue at this level until the Company has recovered its costs.

The government was entitled to 25 percent and 20 percent of the profits from Hazira and Surat, respectively.

Operating Expenses

Operating expenses increased year-to-date compared to the same period in the prior year due to costs related to maintenance of the onshore terminal and subsea systems. Operating costs per mcfe have increased as a result of decreased production with no corresponding decrease in operating costs as the majority of the operating costs are fixed.

Depletion, Depreciation and Accretion

The depletion rate increased as a result of the revision to the reserve volumes and future costs included in the March 31, 2011 reserve report. The effect of the increased depletion rate on the depletion expense was partially offset by decreased production.

Income Taxes

Current income tax expense relates to the Hazira and Surat blocks. There was a recovery in the quarter related to a change in the full year forecast of income. Year-to-date, current income tax expense has increased as a result of recognizing adjustments related to prior year tax provisions.

The Company pays minimum alternate tax (MAT) at a rate of 19 percent of accounting profits, calculated in accordance with Indian generally accepted accounting principles, and records this as MAT expense. MAT has decreased from the prior year periods primarily as a result of decreased revenues.

Deferred income tax liability is calculated by first determining the difference between book value of assets and liabilities in the financial statements and the remaining tax basis (“temporary differences”). To estimate the deferred tax liability, temporary differences are multiplied by the anticipated tax rate during the period in which the difference is expected to reverse. For the periods ended December 31, 2010, it was anticipated that the temporary differences would largely reverse during the tax holiday period when the tax rate would be nil resulting in no deferred tax liability for the D6 Block in India.

The change in accounting estimate is related to deferred income taxes as a result of revising the method of estimating the amount of taxable temporary differences reversing during the tax holiday period. Although the Company does not expect a change of this magnitude to occur in the future, there may be future changes in this estimate as the circumstances and facts surrounding this estimate change.

The deferred income tax expense in the current year is comprised of the change in temporary differences partially offset by a MAT credit. The deferred income tax expense relates to revaluing the Indian-rupee based tax pools to U.S. dollars, which due to the weakening of the Indian Rupee resulted in an expense during the period. MAT paid can be carried forward for 10 years and deducted against regular income taxes in future years resulting in a MAT credit, which is recorded as a recovery against the deferred income tax expense.

Contingencies

The Company has contingencies related to gas sales contracts, the profit petroleum calculation and ownership of the 36” pipeline for Hazira and related to income taxes for Hazira and Surat as at December 31 2011. Refer to the consolidated financial statements and notes for the period ended December 31, 2011 for a complete discussion of the contingencies.

BANGLADESH

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Natural gas revenue	12,453	15,222	36,775	41,733
Condensate revenue	1,970	1,902	5,934	4,460
Profit petroleum	(4,882)	(5,787)	(14,459)	(15,584)
Production and operating expenses	(2,277)	(2,319)	(5,998)	(5,964)
Depletion expense	(3,336)	(3,258)	(9,185)	(8,799)
Exploration and evaluation expenses	(541)	(322)	(933)	(505)
Current income tax expense	-	-	-	(6)
Segment profit (1)	3,386	5,438	12,133	15,335
Daily natural gas sales (Mcf/d)	58,428	71,437	57,952	65,497
Daily condensate sales (bbls/d) (1)	189	234	187	196
Operating costs ($/Mcfe)	0.41	0.35	0.37	0.33
Depletion rate ($/Mcfe)	0.61	0.49	0.57	0.48

(1) Segment profit is a non-IFRS measure as calculated above. Segment profit includes the results from Block 9 and Feni in Bangladesh. Production from Feni ceased in April 2010.

Revenue, Profit Petroleum, Depletion and Operating Expenses

The Bangora-1 well is producing at a consistent level, which is lower than the prior year periods due to a mechanical problem that cannot be remedied in a cost-effective manner. Production from this well is expected to continue at no higher than current levels. The decrease in production is the cause of the revenue decline as the gas price was consistent during the periods at $2.32/Mcf.

Condensate production in the prior year's quarter increased as a result of the installation of the dew-point control unit. Thereafter, condensate production decreased as a result of the decrease in production from the Bangora-1 well. The effect of the decreased production on revenue was more than offset by increased price during the year.

Pursuant to the terms of the PSC for Block 9, the Government of Bangladesh was entitled to 61 percent of profit gas in the year and prior year, which equates to 34 percent of revenues while the Company is recovering historical capital costs. Overall, profit petroleum expense decreased due to decreased revenues from Block 9.

Depletion expense increased on a unit-of-production basis as a result of the addition of the dew-point control unit.

Contingencies

The Company has contingencies related to a receivable for production from the Feni field in Bangladesh and various claims raised against the Company as at December 31, 2011. Refer to the consolidated financial statements and notes for the period ended December 31, 2011 for a complete discussion of the contingencies.

NETBACKS

The following tables outline the Company's operating, funds from operations and earnings netbacks (all of which are non-IFRS measures):

	Three months ended December 31, 2011			Three months ended December 31, 2010		
($/Mcfe)	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	4.82	2.63	4.23	4.69	2.56	4.16
Royalties	(0.25)	-	(0.18)	(0.24)	-	(0.18)
Profit petroleum	(0.13)	(0.89)	(0.34)	(0.10)	(0.86)	(0.29)
Production and operating expense	(0.49)	(0.41)	(0.48)	(0.40)	(0.35)	(0.39)
Operating netback	3.95	1.33	3.23	3.95	1.35	3.30
Other income			0.33			-
G&A			(0.08)			(0.08)
Net finance expense			(0.25)			(0.27)
Current income tax recovery			0.06			-
Minimum alternate tax			(0.31)			(0.34)
Funds from operations netback			2.98			2.61
Production and operating expenses			(0.02)			(0.02)
Exploration and evaluation costs			(2.84)			(0.76)
Other expense			(0.32)			(0.24)
Gain on short-term investment			0.12			0.01
Deferred income tax (expense) / reduction			(0.34)			0.34
Net finance expense			(0.29)			(0.06)
Depletion expense			(1.29)			(0.92)
Earnings netback			(2.00)			0.96

	Nine months ended December 31, 2011			Nine months ended December 31, 2010		
($/Mcfe)	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	4.93	2.63	4.35	4.68	2.52	4.21
Royalties	(0.25)	-	(0.19)	(0.25)	-	(0.19)
Profit petroleum	(0.11)	(0.89)	(0.30)	(0.10)	(0.85)	(0.26)
Production and operating expense	(0.45)	(0.37)	(0.43)	(0.33)	(0.33)	(0.33)
Operating netback	4.12	1.37	3.43	4.00	1.34	3.43
Other income			0.10			-
G&A			(0.09)			(0.08)
Net finance expense			(0.30)			(0.23)
Current income tax expense			(0.05)			(0.01)
Minimum alternate tax			(0.29)			(0.38)
Funds from operations netback			2.80			2.73
Production and operating expenses			(0.02)			(0.02)
Exploration and evaluation costs			(1.80)			(0.97)
Other expense			(0.53)			(0.22)
(Loss) on short-term investment			(0.10)			(0.16)
Deferred income tax (expense) / reduction			(1.00)			0.38
Net finance expense			(0.21)			(0.04)
Depletion expense			(1.29)			(0.93)
Earnings netback			(2.15)			0.77

The netback for India, Bangladesh and in total for the Company is a non-IFRS measure calculated by dividing the revenue and costs for each country and in total for the Company by the total sales volume for each country and in total for the Company measured in Mcfe. Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl:6 Mcf.

CORPORATE

	Three months ended December 31,		Nine months ended December 31,	
(thousands of U.S. dollars)	2011	2010	2011	2010
General and administrative	1,529	2,113	5,544	6,275
Other expense—share-based compensation	5,158	5,821	17,865	16,373
Other expense—impact of option cancellation	-	-	13,913	-
Other expense—depreciation and other	1,226	769	2,491	2,160
Finance expense	8,135	7,547	23,876	25,755
Foreign exchange loss / (gain)	4,787	1,960	12,030	(1,830)
(Gain) / loss on short-term investments	(2,384)	(166)	6,184	13,504

General and administrative

In the current year, the general and administrative costs have decreased primarily as a result of increased overhead recoveries from the branch offices. The effect was partially offset by increased use of outside legal services.

Other expense – Share-based compensation expense and impact of option cancellation

The decrease in share-based compensation expense in the quarter is primarily a result of employees spending more time on exploration activities and the associated expense has been recorded in exploration expense as opposed to general and administrative expense. Year-to-date, share-based compensation expense increased as a result of an increase in the number of options being expensed on the addition of corporate personnel required for expanded operations.

Stock options were cancelled during the period and accounting rules require immediate expense recognition as if the cancelled options had vested immediately resulting in a $14 million charge to other expense in the period.

Finance expense

	Three months ended December 31,		Nine months ended December 31,	
(thousands of U.S. dollars)	2011	2010	2011	2010
Interest expense	5,449	5,735	16,322	20,569
Accretion expense	1,958	1,778	5,699	5,059
Other	728	34	1,855	127
Finance expense	8,135	7,547	23,876	25,755

Interest expense decreased as a result of the repayment of the long-term debt in October 2010.

Accretion expense is on the Company's convertible debentures and decommissioning obligations. The recorded liability for the convertible debenture increases as time progresses to the maturity date resulting in a higher accretion expense than in the prior period. Other expense includes the costs of arranging financing.

Foreign Exchange

	Three months ended December 31,		Nine months ended December 31,	
(thousands of U.S. dollars)	2011	2010	2011	2010
Realized foreign exchange loss / (gain)	1,035	2,073	4,403	(1,311)
Unrealized foreign exchange loss / (gain)	3,752	(113)	7,627	(519)
Total foreign exchange loss / (gain)	4,787	1,960	12,030	(1,830)

The Company's realized foreign exchange losses and gains arise because of the difference between the Indian rupee to U.S. dollar exchange rate at the time of recording individual accounts receivable and accounts payable compared to the exchange rate at the time of receipt of funds to settle recorded accounts receivable and payment to settle recorded accounts payable.

The unrealized foreign exchange loss in the current periods arose primarily on the translation of the Indian-rupee denominated income tax receivable to U.S. dollars as a result of the weakening of the rupee versus the U.S. dollar.

There were additional foreign exchange gains in the year on U.S. dollar cash held by the parent whose functional currency is the Canadian dollar. An offsetting entry increases the accumulated other comprehensive income but does not flow through the income statement.

Short-term Investments

The gain on short-term investments in the quarters and losses year-to-date were a result of marking the short-term investments to market value. The Company sold investments during the period resulting in realized losses of $1 million. The majority of the losses had been included in income in prior periods as the investments have been marked to market since the time of purchase.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2011, the Company had total restricted and unrestricted cash of $86 million (March 31, 2011 - $126 million). The Company's unrestricted cash position decreased by $41 million during the period primarily as a result of the closing of the acquisition of Block 5(c) in Trinidad resulting in payment of the remaining $58 million towards the purchase price and capital spending, partially offset by cashflow from operations.

The Company had a working capital deficit of $253 million at December 31, 2011 ($119 million – March 31, 2011), calculated as current assets less current liabilities. The primary reason for the change from a surplus to a deficit is the inclusion of the convertible debentures of $299 million in current liabilities as they are due within one year. The Company has the right to settle the debentures with equity. The Company collected $30 million during the period that had been advanced for a new venture with conditions precedent. The conditions were not met and the advance was returned to the Company during the period reducing the account receivable balance. The accounts payable balance increased as a result of increased drilling and seismic activity in Trinidad during the period.

On December 30, 2009, the Company entered into a Cdn$310 million convertible debenture credit facility (the "Debentures"). The Debentures bear a coupon rate of 5 percent and mature on December 30, 2012. The interest is paid semi-annually in arrears on January 1st and July 1st of each year. Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn$110.50 per common share until 60 days prior to the maturity date. In May 2011, the terms of the debentures were altered such that the Company now may elect to convert all of the Debentures at maturity into common shares at a 6 percent discount to the weighted average trading price for the 20 trading days prior to the election.

In January 2012, the Company entered into a three-year facility agreement for a $225 million credit facility and a $25 million operating facility for general corporate purposes and has not borrowed against this facility.

The Company has estimated the cost of its remaining work commitments as at December 31, 2011 under the various PSCs including $10 million for drilling three wells in the D4 Block, up to $2 million to drill the remaining well required for the Cauvery Block, $267 million for the remaining seismic and planned drilling for Indonesian blocks, $23 million for drilling in Kurdistan, $40 million for drilling in Madagascar and $299 million for the remaining seismic and drilling commitments for the Trinidad blocks.

The Company has a commitment to a non-stop four year drilling campaign, with a fifth year, at the option of the Company. The gross spending will be approximately $1.5 billion.

The cost of the remainder of the Company's planned capital program for Fiscal 2012 is $66 million, which is comprised of $57 million for exploration and $9 million for development.

The Company expects that it will use cash on hand, cash from operations and its current credit facility in order to fund its planned capital program for Fiscal 2012. Cashflow from operations is affected by production levels, by fluctuations in foreign exchange rates, changes in operating costs and the market price of oil. The Company has entered into gas contracts for production from the D6 Block with a gas price that is fixed at $3.95/Mcf until March 2014.

During Fiscal 2012, due to a pre-emptive right, Niko had the opportunity to increase its net interest by 30 percent in each or all of the D6, NEC-25 and D4 blocks in India. Niko has declined to purchase the additional interest.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company, in thousands of U.S. dollars unless otherwise indicated, for the eight most recently completed quarters to December 31, 2011:

Three months ended	Mar. 31, 2011	June 30, 2011	Sept. 30, 2011	Dec. 31, 2011
Oil and natural gas revenue (1)	94,168	88,277	86,810	74,789
Net income (loss)	6,234	(54,983)	(43,916)	(40,405)
Per share				
Basic ($)	0.12	(1.07)	(0.85)	(0.78)
Diluted ($)	0.12	(1.07)	(0.85)	(0.78)

Three months ended	Mar. 31, 2010 (2)	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010
Oil and natural gas revenue (1)	110,622	104,687	105,781	99,220
Net income (loss)	38,667	14,072	23,785	25,806
Per share				
Basic ($)	0.77	0.28	0.47	0.50
Diluted ($)	0.76	0.27	0.46	0.50

(1) Oil and natural gas revenue is oil and natural gas sales less royalties and profit petroleum expense.

(2) The Fiscal 2010 comparative numbers are non-adjusted Canadian GAAP amounts.

Gas production from the D6 Block commenced in the quarter ended June 30, 2009 and ramped-up during the subsequent quarters, substantially increasing revenues in each quarter to the quarter ended September 30, 2010. D6 gas production began to decline in the subsequent quarters due to well performance. Operating expense increased as additional wells in the D6 Block came on-stream and in 2010 when gas production commenced from the MA oil field.

Net income in the quarters were affected by:

- The Company repaid its long-term debt in October 2010 decreasing finance expense, thereafter.
- The Company's short-term investments are valued at fair value, which is the quoted market price. Gains and losses are recognized throughout the quarters based on fluctuations in the market prices.
- Net income for the quarters from June 30, 2010 indicated above are stated under IFRS and the Company expensed a portion of the exploration and evaluation costs during these quarters decreasing net income. In the quarter ended March 31, 2010, exploration and evaluation costs were capitalized.
- For the quarter ended June 30, 2011, there was a change in accounting estimate related to deferred income tax expense. There was a revision in the method of estimating the amount of taxable temporary differences reversing during the tax holiday period.
- For the quarter ended September 30, 2011, there was a $14 million expense upon cancellation of stock options to recognize the remainder of the expense associated with the options.
- Depletion expense increased in the quarters ended March 31, 2010 and again in March 31, 2011 as a result of revisions to the reserves and estimated future costs to develop the reserves.
- In the quarter ended March 31, 2011, $9.7 million fine was recorded related to the Company's guilty plea to one count of bribery under the Corruption of Foreign Public Officials Act relating to two specific instances that occurred in 2005.

RELATED PARTIES

The Company has a 45 percent interest in a Canadian property that is operated by a related party, a Company owned by the President and CEO of Niko Resources Ltd. This joint interest originated as a result of the related party buying the interest of the third-party operator of the property in 2002. The transactions with the related party are not significant to the operations or the consolidated financial statements. The transactions with the related party are measured at the exchange amount, which is the amount agreed to between related parties.

FINANCIAL INSTRUMENTS

Financial instruments of the Company consist of short-term investments, accounts receivable, long-term accounts receivable, accounts payable and accrued liabilities and convertible debentures.

The Company is exposed to fluctuations in the value of its cash, accounts receivable, short-term investments, accounts payable and accrued liabilities due to changes in foreign exchange rates as these financial instruments are partially or wholly denominated in Canadian dollars and the local currencies of the countries in which the Company operates. The Company manages the risk by converting cash held in foreign currencies to U.S. dollars as required to fund forecast expenditures. The Company is exposed to changes in foreign exchange rates as the future interest payments on the convertible debentures are in Canadian dollars.

The Company is exposed to changes in the market value of the short-term investments.

The Company is exposed to credit risk with respect to all of its financial instruments if a customer or counterparty fails to meet its contractual obligations. The Company has deposited the cash and restricted cash with reputable financial institutions, for which management believes the risk of loss to be remote. The Company takes measures in order to mitigate any risk of loss with respect to the accounts receivable, which may include obtaining guarantees.

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into physical commodity contracts for the sale of natural gas, which manages this risk. The Company does so in the normal course of business by entering into contracts with fixed gas prices. The contracts are not classified as financial instruments because the Company expects to deliver all required volumes under the contracts. No amounts are recognized in the consolidated financial statements related to the contracts until such time as the associated volumes are delivered. The Company is exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the current year, calculated annually, for the D6 gas contracts.

The fair values of accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The fair value of the short-term investments is based on publicly quoted market values. A gain on the recognition of the short-term investments at fair value of $2 million was recognized in income in the quarter (loss of $6 million year-to-date). The Company realized previously recorded mark-to-market losses on the sale of investments of $1 million year-to-date. The fair value of the long-term account receivable for gas revenue receivable from Petrobangla (see note 8 to the interim financial statements for the period ended December 31, 2011 for details) is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years.

The debt component of the convertible debentures has been recorded net of the fair value of the conversion feature. The fair value of the conversion feature of the debentures included in shareholders' equity at the date of issue was $15 million. The fair value of the conversion feature of the debentures was determine based on the discounted future payments using a discount rate of a similar financial instrument without a conversion feature compared to the fixed rate of interest on the debentures. Interest and financing expense of $5 million in the quarter ($16 million year-to-date) was recorded for interest expense and accretion of the discount on the convertible debentures.

CRITICAL ACCOUNTING ESTIMATES

The Company makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements of the Company.

The critical accounting estimates include oil and natural gas reserves, depletion, depreciation and amortization expense, asset impairment, decommissioning obligations, the amount and likelihood of contingent liabilities and income taxes. The critical accounting estimates are based on variable inputs including:

- estimation of recoverable oil and natural gas reserves and future cash flows from the reserves;
- geological interpretations, exploration activities and success or failure, and the Company's plans with respect to the property and financial ability to hold the property;
- risk-free interest rates;
- estimation of future abandonment costs;
- facts and circumstances supporting the likelihood and amount of contingent liabilities; and
- interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net earnings as a result of their impact on the depletion rate, decommissioning obligations, asset impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant and equipment, decommissioning obligations and accounts payable.

For a complete discussion of the critical accounting estimates, please refer to the MD&A for the Company's fiscal year ended March 31, 2011, available at www.sedar.com.

INITIAL ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February 2008, the Accounting Standards Board confirmed that IFRS will be required for interim and annual reporting by publicly accountable enterprises effective for January 1, 2011 including 2010 comparative information. The consolidated financial statements for the period ended December 31, 2011 have been prepared in accordance with IFRS applicable to the preparation of interim financial statements including International Accounts Standard (IAS) 34, "Interim Financial Reporting" and IFRS 1 "First-time Adoption of International Financial Reporting Standards".

The accounting policies adopted by the Company under IFRS are set out in note 2 to the consolidated financial statements for the period ended December 31, 2011. Note 27 to the same consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of certain transition elections and significant changes in accounting policies from those used in the Company's Canadian IFRS consolidated financial statements for fiscal 2011.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The International Accounting Standards Board (IASB) has issued IFRS 9 "Financial Instruments" to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

In May 2011, the IASB issued or amended a number of standards that will be effective for annual periods beginning on or after January 1, 2013.

Three new standards are IFRS 10 "Consolidated Financial Statements", IFRS 11 "Joint Arrangements" and IFRS 12 "Disclosure of Interests in Other Entities". IFRS 10 establishes a single control model that applies to all entities and will require management to exercise judgment to determine which entities are controlled and need to be consolidated by the parent. The Company will continue to consolidate all of its wholly-owned subsidiaries and is currently assessing the accounting impact of its investments in other companies. IFRS 11 replaces IAS 31 "Interest in Joint Ventures" and SIC-13 "Jointly-controlled Entities – Non-monetary Contributions by Venturers". IFRS 11 identifies two forms of joint ventures when there is joint control: joint operations and joint ventures. Joint operations are accounted for using proportionate consolidation and joint ventures are accounted for using the equity method. IFRS 11 focuses on the nature of the rights and obligations associated with the joint arrangements and the Company is currently evaluating the effect of this standard on its joint arrangements. IFRS 12 introduces a number of new disclosures related to consolidated financial statements and interests in subsidiaries, joint arrangements, associates and structured entities.

As a result of the new standards described above, the IAS has amended IAS 28 "Investments in Associates and Joint Ventures" to prescribe the accounting for investments in associates and to set out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

The IASB published IFRS 13 "Fair Value Measurement" which provides a precise definition of fair value and a single source of fair value measurement disclosures requirements for use across IFRSs.

The IASB reissued IAS 27 "Separate Financial Statements" to focus solely on accounting and disclosure requirements when an entity presents separate financial statements that are not consolidated financial statements.

The Company is currently assessing the disclosure impact of the standards listed above on its consolidated financial statements.

DISCLOSURE CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer are responsible for designing disclosure controls and procedures or causing them to be designed under their supervision and evaluating the effectiveness of the Company's disclosure controls and procedures. The Company's Chief Executive Officer and Chief Financial Officer oversee the design and evaluation process and have concluded that the design and operation of these disclosure controls and procedures were effective in ensuring material information relating to the Company required to be disclosed by the Company in its annual filings or other reports filed or submitted under applicable Canadian securities laws is made known to management on a timely basis to allow decisions regarding required disclosure.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of the Company's internal controls over financial reporting. The Chief Executive Officer and Chief Financial Officer have overseen the design and evaluation of internal controls over financial reporting and have concluded that the design and operation of these internal controls over financial reporting were effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes in internal controls over financial reporting during the period ended December 31, 2011. In August 2011, the Company hired a dedicated employee to function as the Chief Compliance Officer and perform the duties previously fulfilled by an existing officer. The Chief Compliance Officer reports to the Audit Committee.

RISK FACTORS

In the normal course of business the Company is exposed to a variety of actual and potential events, uncertainties, trends and risks. In addition to the risks associated with the use of assumptions in the critical accounting estimates, financial instruments, the Company's commitments and actual and expected operating events, all of which are discussed above, the Company has identified the following events, uncertainties, trends and risks that could have a material adverse impact on the Company:

- The Company may not be able to find reserves at a reasonable cost, develop reserves within required time-frames or at a reasonable cost, or sell these reserves for a reasonable profit;
- Reserves may be revised due to economic and technical factors;
- The Company may not be able to obtain approval, or obtain approval on a timely basis for exploration and development activities;
- Changing governmental policies, social instability and other political, economic or diplomatic developments in the countries in which the Company operates;
- Changing taxation policies, taxation laws and interpretations thereof;
- Adverse factors including climate and geographical conditions, weather conditions and labour disputes;
- Changes in foreign exchange rates that impact the Company's non-U.S. dollar transactions; and
- Changes in future oil and natural gas prices.

For a comprehensive discussion of all identified risks, refer to the Company's Annual Information Form, which can be found at www.sedar.com.

The Company has a number of contingencies as at December 31, 2011. Refer to the notes to the Company's consolidated financial statements for a complete list of the contingencies and any potential effects on the Company.

OUTSTANDING SHARE DATA

At February 8, 2012, the Company had the following outstanding shares:

	Number	Cdn$ Amount (1)
Common shares	51,641,845	1,325,399,000
Preferred shares	Nil	Nil
Stock options	3,831,253	-

(1) This is the dollar amount received for common shares issued excluding share issue costs and is presented in Canadian dollars. The U.S. dollar equivalent at February 8, 2012 is $1,171,435,000.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands of U.S. dollars)	As at Dec. 31, 2011	As at March 31, 2011	As at April 1, 2010
Assets		(note 27)	(note 27)
Current assets			
Cash and cash equivalents	67,000	108,342	196,813
Restricted cash (note 4)	6,240	7,704	28,245
Accounts receivable (note 5)	59,877	75,160	44,298
Short-term investments (note 6)	7,137	14,922	32,081
Inventories (note 7)	10,870	7,212	7,255
	151,124	213,340	308,692
Restricted cash (note 4)	12,467	10,232	21,026
Long-term accounts receivable (note 8)	25,969	46,549	29,920
Long-term investment	2,704	2,830	-
Exploration and evaluation assets (note 9)	903,305	762,221	708,478
Property, plant and equipment (note 10)	682,485	763,019	864,444
Income tax receivable	26,154	34,747	27,299
Deferred tax asset	-	56,803	20,410
	1,804,208	1,889,741	1,980,269
Liabilities			
Current liabilities			
Accounts payable	99,007	87,305	121,810
Current tax payable	1,297	2,351	2,072
Finance lease obligation	4,804	4,804	4,278
Borrowings (note 11)	-	-	154,811
Convertible debentures (note 12)	299,368	-	-
	404,476	94,460	282,971
Decommissioning obligation (note 13)	33,584	31,454	27,117
Finance lease obligation	44,888	48,475	53,278
Borrowings (note 11)	-	-	38,003
Deferred tax liabilities	235,879	227,746	227,746
Convertible debentures (note 12)	-	309,221	291,063
	718,827	711,356	920,178
Shareholders' Equity			
Share capital (note 15)	1,171,425	1,162,319	1,111,593
Contributed surplus	99,638	63,037	45,077
Equity component of convertible debentures	14,765	14,765	14,765
Accumulated other comprehensive income / (loss)	1,609	(8,344)	1,184
Deficit	(202,056)	(53,392)	(112,528)
	1,085,381	1,178,385	1,060,091
	1,804,208	1,889,741	1,980,269

Financial Instruments (note 14)
Segmented Information (note 24)
Guarantees (note 25)
Contingencies (note 26)

The accompanying notes are an integral part of these interim financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(thousands of U.S. dollars, except per share amounts)	Three months ended December 31,		Nine months ended December 31,	
(unaudited)	2011	2010	2011	2010
		(note 27)		(note 27)
Oil and natural gas revenue (note 16)	74,789	99,220	249,877	309,689
Production and operating expenses	(10,116)	(10,816)	(29,221)	(27,915)
Depletion expense	(25,975)	(24,733)	(83,601)	(76,407)
Exploration and evaluation expenses	(57,340)	(20,574)	(116,610)	(79,551)
Gain / (loss) on short-term investments (note 6)	2,384	166	(6,184)	(13,504)
Other income (note 17)	6,453	-	6,453	-
Other expenses (note 18)	(6,384)	(6,590)	(34,269)	(18,533)
General and administrative expenses (note 19)	(1,529)	(2,113)	(5,544)	(6,275)
	(17,718)	34,560	(19,099)	87,504
Finance income	2,102	648	2,704	1,127
Finance expense (note 21)	(8,135)	(7,547)	(23,876)	(25,755)
Foreign exchange (loss) / gain	(4,787)	(1,960)	(12,030)	1,830
Net finance expense	(10,820)	(8,859)	(33,202)	(22,798)
Profit (loss) before income tax	(28,538)	25,701	(52,301)	64,706
Current income tax recovery / (expense)	1,241	105	(3,048)	(1,043)
Minimum alternate tax expense (note 22)	(6,221)	(9,064)	(19,019)	(31,172)
Deferred income tax (expense) / recovery	(6,887)	9,064	(64,936)	31,172
Income tax (expense) / reduction	(11,867)	105	(87,003)	(1,043)
Net (loss) / income	(40,405)	25,806	(139,304)	63,663
Earnings / (loss) per share: (note 23)				
Basic	($0.78)	$0.50	($2.70)	$1.25
Diluted	($0.78)	$0.50	($2.70)	$1.24
Net (loss) / income for the period	(40,405)	25,806	(139,304)	63,663
Foreign currency translation (loss) / gain	(4,479)	(8,227)	9,953	(6,353)
Comprehensive (loss) / income for the period	(44,884)	17,579	(129,351)	57,310

Expense disclosure (note 20)

The accompanying notes are an integral part of these interim financial statements.

CONDENSED INTERIM CONSOLIDATED
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands of U.S. dollars)	Common shares (#)	Share capital	Contributed surplus	Accumulated other comprehensive income / (loss)	Equity component of convertible debentures	Deficit	Total
Balance, April 1, 2010	50,818,110	1,111,593	45,077	1,184	14,765	(112,528)	1,060,091
Options exercised	552,689	38,588	(8,916)	-	-	-	29,672
Share-based compensation expense	-	-	22,434	-	-	-	22,434
Net income for the period	-	-	-	-	-	63,663	63,663
Payment of dividends	-	-	-	-	-	(7,553)	(7,553)
Foreign currency translation	-	-	-	(6,353)	-	-	(6,353)
Balance, December 31, 2010	51,370,799	1,150,181	58,595	(5,169)	14,765	(56,418)	1,161,954
Options exercised	156,102	12,138	(3,047)	-	-	-	9,091
Share-based compensation expense	-	-	7,489	-	-	-	7,489
Net income for the period	-	-	-	-	-	6,234	6,234
Payment of dividends	-	-	-	-	-	(3,208)	(3,208)
Foreign currency translation	-	-	-	(3,175)	-	-	(3,175)
Balance, March 31, 2011	51,526,901	1,162,319	63,037	(8,344)	14,765	(53,392)	1,178,385
Options exercised	114,694	9,106	(2,284)	-	-	-	6,822
Share-based compensation expense	-	-	38,885	-	-	-	38,885
Net (loss) for the period	-	-	-	-	-	(139,304)	(139,304)
Payment of dividends	-	-	-	-	-	(9,360)	(9,360)
Foreign currency translation	-	-	-	9,953	-	-	9,953
Balance, December 31, 2011	51,641,595	1,171,425	99,638	1,609	14,765	(202,056)	1,085,381

The accompanying notes are an integral part of these interim financial statements.

CONDENSED INTERIM CONSOLIDATED STATEMENT OF CASHFLOWS

(unaudited) (thousands of U.S. dollars)	Three months ended December 31,		Nine months ended December 31,	
	2011	2010	2011	2010
Cash flows from operating activities:				
Net (loss) / income	(40,405)	25,806	(139,304)	63,663
Adjustments for:				
Depletion and depreciation expense	27,057	25,501	86,026	78,566
Accretion expense	2,077	1,778	5,818	5,059
Deferred income taxes	6,887	(9,064)	64,936	(31,172)
Unrealized foreign exchange loss (gain)	3,752	(113)	7,627	(519)
(Gain) / loss on short-term investment	(2,384)	(166)	6,184	13,504
Share-based compensation expense	5,642	6,272	33,279	17,704
Other expense / (income)	143	-	74	(1,020)
Change in non-cash working capital	(7,417)	(11,369)	5,767	(26,057)
Change in long-term accounts receivable	(1,964)	(3,289)	23,177	1,636
Net cash (used in) / from operating activities	(6,612)	35,356	93,584	121,364
Cash flows from investing activities:				
Exploration and evaluation additions	(16,350)	(7,394)	(135,413)	(28,167)
Capital additions	(415)	(2,556)	(9,219)	(14,336)
Restricted cash contributions	(3,639)	(500)	(6,230)	(36,589)
Release of restricted cash	-	45,153	4,450	59,706
Addition to investments	-	(1,984)	-	(8,839)
Disposition of investments	-	888	1,106	6,306
Change in non-cash working capital	12,636	(44,627)	16,919	(52,324)
Net cash used in investing activities	(7,768)	(11,020)	(128,387)	(74,243)
Cash flows from financing activities:				
Proceeds from issuance of share capital, net of issuance costs	1,970	15,129	6,822	29,673
Repayment of loans and borrowings	-	(99,089)	-	(192,814)
Reduction in finance lease liability	(1,240)	(1,107)	(3,587)	(3,198)
Dividends paid	(2,969)	(3,099)	(9,360)	(7,553)
Net cash used in financing activities	(2,239)	(88,166)	(6,125)	(173,892)
Change in cash and cash equivalents	(16,619)	(63,830)	(40,928)	(126,772)
Effect of translation on foreign currency cash	194	595	(414)	(107)
Cash and cash equivalents, beginning of period	83,425	133,170	108,342	196,813
Cash and cash equivalents, end of period	67,000	69,935	67,000	69,935

The accompanying notes are an integral part of these interim financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

Niko Resources Ltd. (the "Company") is a limited company incorporated in Alberta, Canada. The addresses of its registered office and principal place of business is 4600, 400 – 3 Avenue SW, Calgary, AB, T2P4H2. The Company is engaged in the exploration for and development and production of oil and natural gas in the countries listed in note 24. The Company's common shares are traded on the Toronto Stock Exchange.

2. Basis of Presentation and Significant Accounting Policies

a. Statement of Compliance

The interim financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting". The interim financial statements are the first financial statements reported under International Financial Reporting Standards (IFRS). "First-time Adoption of International Financial Reporting Standards" has been applied. These interim consolidated financial statements do not include all of the information required for full annual financial statements.

This note outlines the significant accounting policies selected under IFRS, which differ from the Canadian GAAP policies used in the Company's most recent annual financial statements. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1. The impact of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at April 1, 2010, as at and for the nine months ended December 31, 2010 and as at and for the year ended March 31, 2011, is presented in note 27.

The financial statements were approved by the board of directors and authorized for issue on February 8, 2012.

b. Basis of Preparation and Presentation

The financial statements have been prepared on the historical cost basis except for the revaluation of certain financial instruments. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

The condensed interim consolidated financial statements are presented in US dollars and all values are rounded to the nearest thousand dollars ($000), except where otherwise indicated.

c. Basis of Consolidation

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (its subsidiaries). Control is achieved where the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated statement of comprehensive income from the effective date of acquisition and up to the effective date of disposal, as appropriate.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies in line with those used by the Company.

All significant intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

d. Cash and Cash Equivalents

Cash and cash equivalents consist of cash and demand deposits.

e. Business Combinations

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Costs incurred by the Company related to the acquisition are included as an acquisition cost. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in the income statement.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Company reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted when the Company obtains complete information about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognized as of that date.

f. Interests in Joint Ventures

The Company is engaged in oil and gas exploration, development and production through unincorporated joint ventures. The consolidated financial statements include the Company's share of the assets, liabilities and cash flows of the joint venture. The Company combines its share of the joint ventures' individual income and expenses, assets and liabilities and cash flows on a line-by-line basis with similar items in the Company's financial statements. Income taxes are recorded based on the Company's share of the joint venture's activities.

The following table sets out a listing and description of the Company's interests in joint ventures:

Block	Country	Working interest %	Block	Country	Working interest %
Block 9	Bangladesh	60	South East Seram	Indonesia	100
Feni/Chattak	Bangladesh	100	South Matindok	Indonesia	100
D4	India	15	Sunda Strait I	Indonesia	100
D6	India	10	West Papua IV	Indonesia	51
Hazira Field	India	33	West Sageri	Indonesia	100
NEC	India	10	Qara Dagh	Iraq	37
Bone Bay	Indonesia	45	Grand Prix	Madagascar	75
Cendrawasih	Indonesia	45	Indus-X	Pakistan	100
Cendrawasih Bay II	Indonesia	50	Indus-Y	Pakistan	100
Cendrawasih Bay III	Indonesia	50	Indus-Z	Pakistan	100
Cendrawasih Bay IV	Indonesia	50	Indus-North	Pakistan	100
East Bula	Indonesia	55	Block 2AB	Trinidad	35.75
Halmahera-Kofiau	Indonesia	51	Central Range, Shallow Horizon	Trinidad	32.5
Halmahera-Kofiau II	Indonesia	20	Central Range, Deep Horizon	Trinidad	40
Kofiau	Indonesia	100	Guayaguayare, Shallow Horizon	Trinidad	65
Kumawa	Indonesia	45	Guayaguayare, Deep Horizon	Trinidad	80
North Ganal	Indonesia	31	Block 4(b)	Trinidad	100
North Makassar	Indonesia	30	NCMA2	Trinidad	56
Obi	Indonesia	51	NCMA3	Trinidad	80
Seram	Indonesia	55	Block 5(c)	Trinidad	25
South East Ganal I	Indonesia	100	MG Block	Trinidad	70

g. Financial Assets

Financial assets are initially measured at fair value, plus transaction costs, except for those financial assets classified as at fair value through profit or loss, which are initially measured at fair value.

All recognized financial assets are subsequently measured in their entirety at either amortized cost or fair value depending on their classification. The Company classifies financial assets into the following categories: financial assets at fair value through profit or loss; loans and receivables; held-to-maturity investments and available-for-sale financial assets.

Financial assets at fair value through profit or loss are measured at fair value with the corresponding gains or losses recognized in profit or loss. The Company classifies cash and cash equivalents, restricted cash and short-term investments as held-for-trading financial assets.

Loans and receivables and held-to-maturity investments are measured at amortized cost using the effective interest method. The Company classifies accounts receivable and long-term accounts receivables as loans and receivables. The Company does not have any financial instruments classified as held-to-maturity.

Investments in equity instruments that do not have a quoted market price and whose fair value cannot be reliably measured at cost. The Company has one investment in an equity instrument fitting the description above, which is classified as a long-term investment.

Available-for-sale financial assets are recognized at fair value with the gains and losses, except for impairment losses and foreign exchange gains and losses, being recognized in other comprehensive income and transferred to profit or loss when the asset is derecognized or impaired. The Company does not have any financial assets classified as held-for-sale.

The Company assesses whether there is any objective evidence that a financial asset or group of financial assets is impaired at the end of each reporting period. Any loss determined is recognized in profit or loss.

h. Inventories

Inventories of stores, spares and consumables are purchased for use in oil and gas operations and are valued at cost, which is also the net realizable value. The costs of purchase of inventories comprise the purchase price, import duties and other taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials and services.

Inventory of oil and condensate is valued at the lower of the weighted average cost and net realizable value. Cost is comprised of operating expenses that have been incurred in bringing inventories to their present location and condition and the portion of depletion expense associated with the oil and condensate production. The cost of inventories is assigned using the weighted average cost formula, whereby the cost of each barrel of oil or condensate is determined from the weighted average of the cost of each barrel at the beginning of a period and the cost of barrels produced during the period. Net realizable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

i. *Oil and natural gas exploration and development expenditure*

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting as described below.

(i) Pre-license costs - Pre-licence costs are charged against income as incurred.

(ii) Licence and property acquisition costs - Exploration licence and property acquisition costs are capitalized as exploration and evaluation assets pending drilling results on the licence.

(iii) Exploration expenditure - Geological and geophysical exploration costs are charged against income as incurred.

Costs directly attributable to an exploration well are initially capitalized as exploration and evaluation assets. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells, may be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to development assets.

All other exploration costs are expensed when incurred.

(iv) Development and production expenditure

Expenditure for development and production assets including the costs of drilling development wells and the construction of production facilities are capitalized under development assets and transferred to producing assets when they are put in use. After recognition as an asset, development and producing assets are carried at cost less any accumulated depletion and impairment losses.

j. *Other Property, Plant and Equipment*

Items of property, plant and equipment are initially recorded at cost and subsequently measured at cost less accumulated depreciation and impairment losses. Initial costs include expenditure that is directly attributable to the acquisition of the asset. The costs of the day-to-day servicing of items of property, plant and equipment are recognized in the statement of comprehensive income as incurred.

k. *Intangible Assets*

Intangible assets acquired separately and with finite useful lives are carried at cost less accumulated amortization and impairment losses. Amortization of intangible assets with finite useful lives is provided on a straight-line basis over their estimated useful lives. Alternatively, intangible assets with indefinite useful lives are carried at cost less any subsequent accumulated impairment losses.

Gains or losses arising from derecognition of an intangible asset are measured at the difference between the net disposal proceeds and the carrying amount of the asset and are recognized in the consolidated income statement when the asset is derecognized.

l. Depletion and depreciation

Exploration and evaluation assets and development assets are not depreciated.

The net carrying value of producing assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related total proved reserves of oil and natural gas, taking into account estimated future development costs necessary to bring those reserves into production.

Depreciation for finance lease assets is consistent with that for depreciable assets that are owned. Depreciation for finance lease assets is charged based on the unit-of-production method over the life of the reserves.

For other assets, depreciation is recognized in profit or loss on a diminishing balance or straight-line basis depending on the nature of the asset over the estimated useful lives of each group of property, plant and equipment. Land is not depreciated.

The estimated useful lives of other property, plant and equipment are:

Buildings	27 - 30 years
Plant and machinery	7 - 9 years
Office equipment/furniture and fittings	3 - 10 years
Computers	3 - 5 years
Vehicles and aircraft	4 - 7 years
Pipeline	20 years

m. Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in the income statement in the period in which they are incurred.

n. Impairment of Tangible and Intangible Assets

At the end of each reporting period, the Company assesses whether there is any indication that an asset may be impaired. If any such indication exists, the Company estimates the recoverable amount of the asset. Indications include: a significant decline in market value of the asset; significant changes have taken or will take place in the technological; market, economic or legal environment in which the Company operates or in the market to which an asset is dedicated; a significant increase in market interest rates that would affect the discount rate and value of the asset; and the carrying amount of the net assets of the entity is more than its market capitalization.

Irrespective of whether there is any indication of impairment, the Company tests intangible assets with an indefinite useful life and intangible assets not yet available for use for impairment annually by comparing its carrying amount with its recoverable amount.

o. Financial Liabilities and equity instruments issued by the Company

Financial liabilities are initially measured at fair value, plus transaction costs, except for those financial liabilities classified as at fair value through profit or loss, which are initially measured at fair value. All recognized financial liabilities are subsequently measured in their entirety at either amortized cost or fair value depending on their nature.

Financial liabilities at fair value through profit or loss are measured at fair value with the corresponding gains or losses recognized in profit or loss. The Company does not have any financial liabilities at fair value through profit or loss.

A derivative liability that is linked to and must be settled by delivery of an unquoted equity instrument whose fair value cannot be reliably measured is measured at cost. The Company does not have any derivative liabilities.

All other financial liabilities are measured at amortized cost using the effective interest method. The Company classified accounts payable and provisions, long-term debt and convertible debentures as other financial liabilities.

p. Derivative Financial Instruments

Derivative financial instruments are measured at fair value through profit or loss. The Company does not currently have any derivative financial instruments.

q. Leasing

A lease is classified as a finance lease whenever the terms of the lease transfer substantially all the risks and rewards incidental to ownership to the lessee. At the commencement of the lease term, the Company recognizes the finance lease as assets and liabilities in the statements of financial position at the lesser of the fair value of the leased property and the present value of the minimum lease payments. Any initial direct costs of the lessee are added to the amount recognised as an asset.

Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments are apportioned between the finance charge and the reduction of the outstanding liability. The finance charge is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. Finance charges are charged directly against income, unless they are directly attributable to qualifying assets, in which case they are capitalized in accordance with the Group's policy on borrowing costs. Contingent rents are charged as expenses in the periods in which they are incurred.

An operating lease is a lease other than a finance lease.

Lease payments under an operating lease are generally recognised as an expense on a straight-line basis over the lease term.

r. Decommissioning obligations

Production sharing contracts that the Company has entered into indicate an obligation for abandonment of wells and facilities including removal of all equipment and installations and site restoration, collectively termed decommissioning obligations. Provision is made for the estimated cost of decommissioning obligations for a well that has been drilled and for equipment or installations upon completion. The provision is capitalized in the relevant asset category.

The provision for decommissioning obligations is management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The provision is calculated as the present value of the expenditures expected to be required to settle the obligation in the future. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

s. Revenue Recognition

Revenue resulting from the sale of oil, condensate and natural gas from properties in which the Company has an interest with other producers is recognized on the basis of the Company's working interest.

Revenue from the sale of oil, condensate and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is at the delivery point as defined in the various sales contracts. Revenue is measured at the fair value of the consideration received or receivable. Revenue recorded is net of VAT, other sales-related taxes, royalties and the profit oil and gas sold and paid to the various governments as profit sharing.

t. Finance Income and Finance Expense

Finance income is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable.

Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning obligations and borrowings, impairment losses recognized on financial assets and bank charges.

u. *Foreign Currencies*

The individual financial statements of each group entity are presented in the currency of the primary economic environment in which the entity operates (its functional currency), which is U.S. dollars for the foreign entities and Canadian dollars for Canadian entities. For the purpose of the consolidated financial statements, the results and financial position of each group entity are expressed in U.S. dollars, which is the presentation currency for the consolidated financial statements.

In preparing financial statements of the individual entities, transactions in currencies other than the entity's functional currency (foreign currencies) are recognized at the rates of exchange prevailing at the date of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at that date. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing at the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated. Exchange differences are recognized in the statement of comprehensive income in the period in which they arise.

For the purpose of presenting consolidated financial statements, the assets and liabilities of the Canadian entities with the Canadian dollar as their functional currency are expressed in U.S. dollars using exchange rates prevailing at the end of the reporting period. Income and expense items are translated at the average exchange rates for the period. Exchange differences arising, if any, are recognized in other comprehensive income and accumulated in equity.

v. *Share-based Payments*

The Company has a share-based compensation plan as described in note 15(b). All share-based awards of the Company are equity settled. Compensation expense associated with the plan is calculated and, recognized in net income or capitalized, over the vesting period of the stock option with a corresponding increase in contributed surplus. The consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

w. *Taxation*

Income tax expense is the sum of current tax, minimum alternate tax and deferred tax.

Current tax is the amount of income taxes payable in respect of the taxable profit for the period. Taxable profit differs from profit as reported in the consolidated statement of comprehensive income because of items of income or expense that are taxable or deductible in other years and items that are never taxable or deductible. The Company's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the end of the reporting period.

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax bases used in the calculation of taxable profit. Deferred tax liabilities are the amounts of income taxes payable in future periods in respect of taxable temporary differences. Deferred tax assets are the amounts of income taxes recoverable in future periods in respect of deductible temporary differences and the carry-forward of unused tax losses and unused tax credits.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint ventures, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable there will be sufficient taxable profits against which to utilise the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realized, based on tax rates and tax laws that have been enacted or substantively enacted by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Company expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Company intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax are recognized as an expense or income in net income, except when they relate to items that are recognized outside profit or loss (whether in other comprehensive income or directly in equity), in which case the tax is also recognized outside profit or loss, or where they arise from the initial accounting for a business combination. In the case of a business combination, the tax effect is included in the accounting for the business combination.

3. Management's judgements and estimation uncertainty

The preparation of the consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. By their nature, these estimates are subject to measurement uncertainty and actual results may differ from those estimated.

Significant estimates and judgement made by management in the preparation of these interim consolidated financial statements are as follows:

- Amounts recorded for depletion and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.
- Amounts recorded for decommissioning obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.
- The fair value of the long-term account receivable is based on a discount rate and timing of collection.
- Compensation costs recognized for the share-based compensation plan are subject to the estimate of what the ultimate payout will be using the Black-Scholes-Merton model, which is based on significant assumptions such as volatility, expected life, expected dividends and expected forfeiture rates.
- Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Management makes certain judgements in estimating the timing of temporary difference reversals and the likelihood that deferred tax assets will be realized from future taxable earnings. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

4. Restricted cash

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Current portion of restricted cash			
Guarantees (1)	6,240	7,704	21,838
Funds restricted under the facility agreement (2)	-	-	6,407
	6,240	7,704	28,245
Non-current portion of restricted cash			
Guarantees (1)	7,191	3,947	1,500
Funds restricted under the facility agreement (2)	-	-	14,489
Site restoration fund (3)	5,276	6,285	5,037
	12,467	10,232	21,026

(1) The Company has performance security guarantees related to the work commitments for exploration blocks. The Company is required to provide funds to support the guarantees in the amounts indicated above. See note 25 for details of the guarantees.

(2) The cash that was restricted in accordance with the facility agreement was released upon repayment of the long-term debt.

(3) In accordance with the Site Restoration Fund Scheme, 1999 in India, the Company is required to accumulate funds in a separate restricted account related to future decommissioning obligations. The funds may be used for site restoration on the expiry or termination of an agreement or relinquishment of part of the contract area.

5. Accounts receivable

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Oil and gas revenues receivable	24,120	34,055	36,138
Receivable from joint venture partners	19,674	3,339	696
Advances to vendors	2,027	33,809	3,252
Prepaid expenses and deposits	1,065	1,974	695
VAT receivable	12,478	1,458	160
Other receivables	513	525	3,357
	59,877	75,160	44,298

6. Short-term investments

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Opening balance	14,922	32,081
Purchases	-	6,135
Disposals	(1,106)	(11,103)
Loss on short-term investments	(6,184)	(12,720)
Foreign exchange	(495)	529
Closing balance	7,137	14,922

7. Inventories

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Stock, spares and consumables	10,386	6,849	6,999
Oil and condensate inventories	484	363	256
	10,870	7,212	7,255

8. Long-term accounts receivable

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Gas revenue receivable	22,995	22,995	22,928
Joint venture receivable - 36” pipeline	2,974	3,554	6,449
Cash call receivable from joint venture partner	-	-	543
Deposit on acquisition of Block 5c	-	20,000	-
	25,969	46,549	29,920

Gas revenue receivable: The gas revenue receivable balance is for the natural gas sales to Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) for production from the Feni field in Bangladesh. The Company produced natural gas from the Feni field from November 2004 to April 2010 and delivered the natural gas to Petrobangla for the duration.

Receipt of the outstanding amount is being delayed as a result of various claims raised against the Company, which are described in notes 26(a) and (b). Although the Company expects to collect the full amount of the receivable, the timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company. As a result, the receivable has been classified as long-term and discounted using a risk-adjusted rate of 6.5 percent to reflect the delay in collection of these amounts.

Joint venture receivable – 36-inch pipeline: The Company has recognized a receivable for a refund of previously paid profit petroleum and a receivable from its joint venture partner as a result of the award of ownership of a 36-inch pipeline that is connected to the Hazira facilities. See further discussion in note 26(f).

Deposit on acquisition of Block 5(c): In December 2010, the Company signed an agreement to acquire a 25 percent interest in Block 5(c), located 24 kilometres off the east coast of Trinidad. The Company had paid $20 million as a deposit against the purchase price at March 31, 2011. The Company closed the acquisition of Block 5(c) in June 2011 and the deposit was moved to exploration and evaluation assets.

9. Exploration and evaluation assets

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Opening balance	762,221	708,478
Additions during the period	147,038	54,018
Transfers	-	(275)
Disposals	(3,000)	-
Foreign currency translation loss	(2,954)	-
Closing balance	903,305	762,221

10. Property, plant and equipment

a. Development assets

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Opening balance	18,421	4,572
Additions	7,512	22,803
Transfers	(6,547)	(8,954)
Closing balance	19,386	18,421

b. Producing assets

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Cost		
Opening balance	1,019,696	1,012,905
Transfers	5,741	8,134
Disposals	-	(1,464)
Foreign currency translation (loss) / gain	(124)	121
Closing balance	1,025,313	1,019,696
Accumulated depletion		
Opening balance	(312,767)	(203,463)
Additions	(83,601)	(109,184)
Foreign currency translation gain / (loss)	124	(120)
Closing balance	(396,244)	(312,767)
Net producing assets	629,069	706,929

c. Other Property, plant and equipment

(thousands of U.S. dollars)	Land and buildings	Vehicles, helicopters and aircraft	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, April 1, 2011	18,108	2,395	5,978	10,752	37,233
Additions / Transfers	233	-	1,597	23	1,853
Disposals	-	-	(80)	-	(80)
Foreign currency translation loss	-	-	(87)	-	(87)
Balance, December 31, 2011	18,341	2,395	7,408	10,775	38,919
Depreciation					
Balance, April 1, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Additions	(933)	(263)	(760)	(469)	(2,425)
Disposals	-	-	26	-	26
Foreign currency translation gain	-	-	64	-	64
Balance, December 31, 2011	(5,813)	(1,411)	(4,060)	(7,207)	(18,491)
Net book value, December 31, 2011	12,528	984	3,348	3,568	20,428

(thousands of U.S. dollars)	Land and buildings	Vehicles, helicopters and aircraft	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, April 1, 2010	16,299	2,445	4,257	9,928	32,929
Additions	1,809	-	1,643	824	4,276
Disposals	-	(50)	-	-	(50)
Foreign currency translation loss	-	-	78	-	78
Balance, March 31, 2011	18,108	2,395	5,978	10,752	37,233
Accumulated depreciation					
Balance, April 1, 2010	(3,322)	(901)	(2,839)	(5,891)	(12,953)
Additions	(1,558)	(260)	(516)	(847)	(3,181)
Disposals	-	13	-	-	13
Foreign currency translation gain	-	-	(35)	-	(35)
Balance, March 31, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Net book value, March 31, 2011	13,228	1,247	2,588	4,014	20,597

d. Capital work-in-progress

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011
Capital work-in-progress	13,602	16,592

11. Borrowings

a. In March 2011, the Company entered into a three-year credit facility agreement for a $40 million (or the equivalent in Canadian dollars) revolving demand facility. The Company had not drawn on the facility at December 31, 2011. In January 2012, the facility was replaced with a three-year facility agreement for a $225 million three year, extendible, revolving credit facility and a $25 million three year, extendible, operating facility pursuant to a credit agreement with a syndicate of banks and financial institutions. The facilities are available for general corporate purposes and bear interest at the U.S. dollar LIBOR rate plus the applicable margin. The margins range from 1.75 percent to 4.25 percent for depending on a leverage ratio and the type of loan drawn. The facility is secured by a corporate guarantees, demand debentures providing first priority security over personal property and pledges of shares of certain subsidiaries.

b. In April 2011, the Company entered into an agreement under which it could issue performance security guarantees up to an aggregate amount of $36.5 million. The agreement for the Company's account performance security guarantee was cancelled in July 2011.

12. Convertible debentures

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Opening balance	309,221	291,063
Accretion expense	4,127	4,766
Foreign currency translation	(13,980)	13,392
Closing balance	299,368	309,221

The Company issued Cdn $310 million, 5 percent convertible debentures (the "Debentures") on December 30, 2009. The Debentures mature on December 30, 2012 with interest paid semi-annually in arrears on January 1st and July 1st of each year. The Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn $110.50 per common share until 60 days prior to the maturity date. In May 2011, the terms of the debentures were altered such that the Company now may elect to convert all of the Debentures at maturity into common shares at a 6 percent discount to the weighted average trading price for the 20 trading days prior to the election.

Interest and accretion on the convertible debentures of $16 million was expensed in the nine months ended December 31, 2011 (December 31, 2010 - $15 million). Interest paid during the nine months ended December 31, 2011 was $16 million (December 31, 2010 - $16 million).

13. Decommissioning obligations

(thousands of U.S. dollars)	Nine months ended December 31, 2011	Year ended March 31, 2011
Opening balance	31,454	27,117
Provisions made during the period	444	3,152
Change in estimate during the period	(5)	(896)
Accretion	1,691	2,081
Closing balance	33,584	31,454

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, estimated costs of removal of all equipment and installations and site restoration and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be $34 million as at December 31, 2011 (March 31, 2011 - $31 million) based on an undiscounted total future liability of $79 million (March 31, 2011 - $78 million). These costs are expected to be incurred over the next four to 15 years. The discount rate used to calculate the net present value of the future decommissioning obligations is the pre-tax rate reflecting current market assessments of the time value of money.

An amount of Rs. 280,920,418 (US$5,275,989) has been deposited with State Bank of India for decommissioning obligations. This amount has been treated as restricted cash included in non-current assets.

14. Financial Instruments

a. Capital risk management

The Company's policy is to maintain a strong capital base and related capital structure. The objectives of this policy are:

(i) To promote confidence in the Company by the capital markets, by investors, by creditors and by government agencies in the countries in which the Company bids for concessions and/or operates;

(ii) To maintain resources required to withstand financial difficulties due to exogenous influences such as financial, political, economic, social or market uncertainties and events; and

(iii) To facilitate the Company's ability to fulfill exploration and development commitments, and to seek and execute growth opportunities.

The Company's capital base includes shareholders' equity and outstanding borrowings as follows:

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Borrowings	-	-	192,814
Convertible debentures	299,368	309,221	291,063
Shareholders' equity	1,085,381	1,178,385	1,060,091

The Company's objective in capital management is to have the flexibility to alter the capital structure to take advantage of capital-raising opportunities in the capital markets, whether they are equity or debt-related. However, the Company would generally use long-term debt either to fund portions of the development of proven properties or to finance portions of possible acquisitions. Exploration is generally funded by cash flow from operations and equity.

To manage capital, the Company uses a rolling three-year projection. The projection provides details for the major components of sources and uses of cash for operations, financing and development and exploration expenditure commitments. Management and the Board of Directors review the projection annually and when contemplating interim financing or expenditure alternatives. The periodic reviews help ensure that the Company has the short-term and long-term ability to fulfill its obligations and to fund ongoing operations.

There were no changes in the Company's approach to capital management during the period.

b. Categories and fair value of financial instruments

Financial instruments are recognized under four categories:

- Financial assets and financial liabilities at fair value through profit and loss
- Held-to-maturity investments
- Loans and receivables
- Available-for-sale financial assets

The Company's short-term investments are classified as held-for-trading, which is a financial asset at fair value through profit or loss. The Company classifies fair value measurements using the following fair value hierarchy that reflects the significance of the inputs used in making the measurements:

- Level 1: Quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3: Inputs for the asset or liability that are not based on observable market date (unobservable inputs).

Short-term investments as at March 31, 2011 and December 31, 2011 have been assessed on the fair value hierarchy describe above and have been classified as Level 1. The fair value of the short-term investments was based on publicly quoted market values. There was a gain of $2 million in the quarter and a loss of $6 million year-to-date (2010 – gain of $0.2 million and a loss of $14 million, respectively) on recognizing the short-term investments at their fair value. The fair values of short-term investments approximate their carrying amounts as they are recognized at fair value.

Cash and cash equivalents and restricted cash are classified as held-for-trading and measured at fair value through profit and loss. Accounts receivable are classified as loans and receivables. The fair values of accounts receivable approximate their carrying value due to their short periods to maturity.

Long-term accounts receivable are classified as loans and receivables. The fair value of the long-term account receivable for gas revenue receivable from Petrobangla (see note 8) is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years. The long-term accounts receivable is carried at estimated fair value.

Accounts payable and accrued liabilities and convertible debentures are classified as other financial liabilities that are not held for trading. The fair values of accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. Interest and accretion expense for the convertible debentures of $5 million was recognized in profit and loss during the quarter and $16 million year-to-date (2010 - $5 million and $15 million, respectively). The carrying value of the Company's convertible debentures approximates the fair value.

Fair value information has not been disclosed for the long-term investment because the fair value cannot be measured reliably. The long-term investment is in common shares of a private oil and gas company and the investment is recorded at the cost of Cdn$3 million (US$3 million). There is not a liquid market for the common shares and liquidation would require a private buyer or for the company to list on a stock exchange. The Company intends to hold this investment for the longer-term.

c. Credit risk management

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from customers. The carrying amounts of the cash and cash equivalents, restricted cash, accounts receivable and the undiscounted amount of the long-term account receivable reflect management's assessment of the maximum credit exposure. The Company takes measures in order to mitigate any risk of loss, which may include obtaining guarantees. There were no changes in the Company's exposure to credit risks or any changes to the Company's processes for managing the risks from the previous period.

The aging of the accounts receivable as at December 31, 2011 was:

0—30 days	48,937
30—90 days (1)	10,065
90—365 days (1)	875
	59,877

(1) Accounts receivable are past due as at December 31, 2011 but not impaired.

The accounts receivable that are not past due are receivable from counterparties with whom the Company has a history of timely collection and the Company considers the accounts receivable collectible.

The long-term account receivable balance consists of gas sales charged to Petrobangla for the production from the Feni field in Bangladesh. Payment of the receivable is being delayed as a result of various claims raised against the Company as described in notes 26 (a,b). The long-term accounts receivable is not considered impaired. The Company considered the delay in payment, the writ and the lawsuit raised against the Company and progress towards resolving these issues in reaching the conclusion that the delay in payment is temporary. Despite the temporary delay in payment, the Company expects to collect the full amount of the receivable. The timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company described in notes 26 (a,b).

d. Liquidity risk management

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company manages this risk by preparing cash flow forecasts to assess whether additional funds are required.

The Company has the following financial liabilities and due dates as at December 31, 2011:

(thousands of U.S. dollars)	Carrying amount	< 1 year	> 1 year
Accounts payable	99,007	99,007	-
Capital lease obligations (1)	49,692	4,804	44,888
Repayment of convertible debentures (2)	299,368	299,368	-

(1) The amount of lease payments is $10.8 million per year until August 2018. The above $50 million represents the carrying value of the liability.

(2) The carrying amount of the convertible debentures is the fair value of $299 million. The amount that will be required to be repaid assuming that the debentures are not converted is Cdn$310 million ($305 million as at December 31 2011).

e. Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and equity prices, will affect the Company's income or the value of its financial instruments. There were no changes in the Company's exposure to market risks or the Company's processes for managing the risks from the previous period.

(i) Currency risk

The majority of the Company's revenues and expenses are denominated in U.S. dollars and the Company holds the majority of its funds in U.S. dollars, except as required to fund dividends and make interest payments on the convertible debentures. As a result, the Company has limited its cash exposure to fluctuations in the value of the U.S. dollar versus other currencies. However, the Company is exposed to changes in the value of the Indian rupee versus the U.S. dollar as they are applied to the Company's working capital, income tax receivable and deferred tax liability of its subsidiaries in India. The Company does not have any foreign exchange contracts in place to mitigate currency risk.

A five percent strengthening of the Indian rupee against the U.S. dollar at December 31, 2011, which is based on historical movements in the foreign exchange rates, would have decreased the net loss by $1 million. This analysis assumes that all other variables remained constant.

The financial instruments are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the cash and cash equivalents, accounts receivable, short-term investment and accounts payable of the Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar. A four percent weakening of the Canadian dollar against the U.S. dollar at December 31, 2011, which is based on historical movement in foreign exchange rates, would have decreased other comprehensive loss by $3 million. This analysis assumes that all other variables remained constant.

(ii) Commodity Price Risk

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into natural gas contracts, which manages this risk. Because the Company has long-term fixed price gas contracts, a change in natural gas prices would not have impacted net income for the period ended December 31, 2011. The Company is exposed to changes in the market price of oil and condensate. In addition, the Company will be exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the following year, calculated annually, for the D6 gas contracts.

(iii) Other price risk

The Company has deposited the cash equivalents with reputable financial institutions, for which management believes the risk of loss to be remote.

The Company is exposed to the risk of fluctuations in the market prices of its short-term investments. An 18 percent change in the publicly quoted market values at the reporting date, which is based on historical changes in market values, would have increased or decreased net loss for the period ended December 31, 2011 by $1.3 million. The fair value was $7.1 million at December 31, 2011.

15. Share capital

a. Fully paid ordinary shares

The Company has authorized for issue an unlimited number of common shares and an unlimited number of preferred shares. The common shares issued are fully paid and the shares have no par value. No preferred shares have been issued.

b. Share options granted under the employee share option plan

The Company has reserved for issue 5,164,160 common shares for granting under stock options to directors, officers, and employees. The options become vested immediately to five years after the date of grant and expire one to six years after the date of grant.

Stock option transactions for the respective periods were as follows:

	Nine months ended December 31, 2011		Year ended March 31, 2011	
	Number of options	Weighted average exercise price (Cdn$)	Number of options	Weighted average exercised price (Cdn$)
Opening balance	4,243,897	85.37	4,056,714	75.88
Granted	781,625	60.74	1,125,687	101.35
Forfeited	(99,750)	85.54	(155,938)	86.62
Cancelled	(587,500)	102.13	-	-
Expired	(431,325)	76.72	(73,775)	92.96
Exercised	(114,694)	58.03	(708,791)	55.33
Closing balance	3,792,253	79.46	4,243,897	85.37
Exercisable	678,561	82.81	702,144	77.15

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2011:

	Outstanding options			Exercisable options	
Exercise Price	Options	Remaining life (years)	Weighted average exercise price (Cdn$)	Options	Weighted average exercise price (Cdn$)
42.03 - 49.99	822,816	2.3	48.85	154,811	49.35
50.00 - 59.99	262,625	4.1	52.09	-	-
60.00 - 69.99	252,125	3.0	63.40	37,750	63.52
70.00 - 79.99	81,250	2.6	74.51	13,500	79.55
80.00 - 89.99	646,063	1.8	86.06	48,250	82.25
90.00 - 99.99	1,278,000	1.8	95.97	376,625	95.63
100.00 - 109.99	420,249	2.9	104.52	43,250	106.58
110.00 - 112.64	29,125	2.5	111.12	4,375	111.30
	3,792,253	2.3	79.46	678,561	82.81

The weighted average share price during the nine months ended December 31, 2011 was $58.66 (year ended March 31, 2011 - $97.47).

c. *Fair value measure of equity instruments granted*

The fair value of each option granted during the quarters was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average inputs:

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Grant-date fair value	Cdn$15.83	Cdn$29.60	Cdn$19.94	Cdn$32.90
Market price per share	Cdn$49.31	Cdn$96.52	Cdn$60.74	Cdn$101.48
Exercise price per option	Cdn$49.31	Cdn$96.52	Cdn$60.74	Cdn$101.48
Expected volatility	44%	40%	42%	42%
Expected life (years)	3.5	3.4	3.8	3.5
Expected dividend rate	0.5%	0.2%	0.4%	0.2%
Risk-free interest rate	1.1%	1.9%	1.6%	2.1%
Expected forfeiture rate	6.0%	6.4%	6.0%	6.7%

Expected volatility was determined based on the historical movements in the closing price of the Company's stock for a length of time equal to the expected life of each option. See note 20 for categorization of share-based payment expense during the period.

16. Revenue

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Natural gas sales	69,338	91,395	224,017	283,895
Oil and condensate sales	15,888	20,517	57,653	63,733
Less:				
Royalties	(3,656)	(4,874)	(12,198)	(16,109)
Government's share of profit petroleum	(6,781)	(7,818)	(19,595)	(21,830)
Oil and natural gas revenue	74,789	99,220	249,877	309,689

Revenues from oil and gas sales to Petrobangla comprised 15 percent of natural gas, oil and condensate sales for the nine months ended December 31, 2011 (2010 – 13 percent).

17. Other income

The Government of Indonesia approved the Company's farm-outs of a portion of its interest in various properties. The proceeds in excess of the recorded asset in relation to these interests is included in earnings for the period.

18. Other expenses

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Share-based compensation expense	5,158	5,821	31,778	16,373
Depreciation	1,082	769	2,425	2,160
Other	144	-	66	-
Other expenses	6,384	6,590	34,269	18,533

19. General and administrative expense

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Salaries	1,086	777	2,277	3,793
Legal fees	653	837	2,791	1,543
Consultants	633	365	663	872
Rent	183	167	565	513
Management fees	161	253	488	420
Audit fees	88	398	339	629
Insurance	242	278	252	294
Office costs	70	39	233	109
Other	170	(180)	882	487
Overhead recoveries from branch offices	(1,757)	(821)	(2,946)	(2,385)
General and administrative expense	1,529	2,113	5,544	6,275

20. Expense disclosure

The Company prepares its statement of comprehensive income classifying costs according to function as opposed to the nature of the costs. As a result, share-based compensation expense is charged to various other headings in the statement of comprehensive income.

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Share-based compensation expense included in:				
Exploration and evaluation assets	292	1,337	767	1,641
Operating expense	484	451	1,501	1,331
Exploration and evaluation expense	1,614	286	4,839	3,089
Other expense	5,158	5,821	31,778	16,373
Total	7,548	7,895	38,885	22,434

The Company prepares its statement of comprehensive income classifying costs according to function as opposed to the nature of the costs. As a result, general and administrative expenses are charged to various other headings in the statement of comprehensive income. General and administrative expenses of $4 million and $12 million for the three and nine months ended December 31, 2011, respectively (2010 - $5 million and $12 million, respectively) are categorized as exploration and evaluation expenses and of $3 million and $8 million for the three and nine months December 31, 2011, respectively (2010 - $3 million and $6 million, respectively) are categorized as production and operating expenses.

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Audit fees	132	413	457	678
Management fees	165	255	497	428
Legal fees	1,047	913	3,467	1,977
Salary	2,588	2,430	7,962	9,283
Insurance	1,779	1,986	4,935	4,455
Security	241	285	688	862
Rent	370	401	1,146	1,143
Travel	315	219	752	633
Consultants	686	465	822	1,064
Non-operating and other	385	715	2,612	2,256
Office costs	802	911	2,453	2,126
Overhead recoveries from partners	(446)	42	(491)	(466)
Total	8,064	9,035	25,300	24,439

21. Finance expense

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Interest expense related to capital lease	1,488	1,603	4,500	4,972
Interest expense on long-term debt	-	276	-	4,135
Interest expense on convertible debentures	3,842	3,856	11,703	11,462
Accretion expense on convertible debentures	1,503	1,252	4,127	3,512
Accretion expense on decommissioning obligations	574	526	1,691	1,547
Bank fees and charges and other finance costs	728	34	1,855	127
Finance expense	8,135	7,547	23,876	25,755

22. Minimum alternate tax

The Company currently pays minimum alternate tax (MAT) for the D6 block at a rate of 19 percent of accounting profits, calculated in accordance with Indian generally accepted accounting principles, and records this as MAT expense in the statement of comprehensive income. MAT paid can be carried forward for 10 years and deducted against regular income taxes in future years. As a result, the Company also recognizes the MAT tax as a deferred tax asset on the statement of financial position and a deferred income tax recovery in the statement of comprehensive income.

23. Earnings per share

The earnings used in the calculation of basic and diluted per share amounts are as follows:

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Net (loss) / income	(40,405)	25,806	(139,304)	63,663

A reconciliation of the weighted average number of ordinary shares for the purpose of calculating basic earnings per share to the weighted average number of ordinary shares for the purpose of calculating diluted earnings per share is as follows:

(thousands of U.S. dollars)	Three months ended December 31, 2011	Three months ended December 31, 2010	Nine months ended December 31, 2011	Nine months ended December 31, 2010
Weighted average number of common shares used in the calculation of basic earnings per share	51,603,054	51,136,407	51,569,074	51,010,008
Shares deemed to be issued for no consideration in respect of employee options	-	376,834	-	389,443
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	51,603,054	51,513,241	51,569,074	51,399,451

As a result of the net loss in the three and nine months ended December 31, 2011, the outstanding stock options of 3,792,253 were considered anti-dilutive and were not included in the diluted per share amounts. The average market value of the Company's common shares for purposes of calculating the dilutive effect of stock options for the three and nine months ended December 31, 2010 was based on quoted market prices for the period that the options were outstanding. Shares issuable upon conversion by the holders of the outstanding debentures of 2,805,430 for the three and nine months ended December 31 2011 (2010 – 2,805,430) are anti-dilutive and are therefore excluded from the weighted average number of common shares for the purposes of diluted earnings per share.

24. Segmented Information

a. Products and services from which reportable segments derive their revenues

The Company's operations are conducted in one business sector, the oil and natural gas industry. All revenues are from external customers.

b. Determination of reportable segments

Geographical areas are used to identify the Company's reportable segments. A geographic segment is considered a reportable segment once its activities are regularly reviewed by the Company's management. The accounting policies of the information of the reportable segments are the same as those described in the summary of significant accounting policies.

c. Segment assets and liabilities, revenues and results

	Nine months ended December 31, 2011		Year ended March 31, 2011	
	Additions to:			
Segment	Exploration and evaluation assets (E&E)	Property, plant and equipment (PP&E) (1)	Exploration and evaluation assets	Property, plant and equipment
Bangladesh	-	-	511	5,435
India	1,060	7,512	22,206	18,125
Indonesia	11,678	-	6,402	-
Kurdistan	23,935	-	20,547	-
Madagascar	9	-	800	-
Pakistan	248	-	-	-
Trinidad	110,108	-	3,552	-
All other	-	1,544	-	4,277
Total	147,038	9,056	54,018	27,837

(1) Excludes changes in capital work-in-progress.

	As at December 31, 2011			As at March 31, 2011			As at April 1, 2010		
Segment	Total E&E	Total PP&E	Total assets	Total E&E	Total PP&E	Total assets	Total E&E	Total PP&E	Total assets
Bangladesh	4,737	34,580	72,001	5,248	42,323	82,057	4,737	50,219	91,886
India	134,826	625,501	836,770	133,929	698,869	990,857	111,998	792,925	1,047,580
Indonesia	509,162	-	531,595	499,810	-	510,905	493,408	125	534,373
Kurdistan	86,774	749	89,974	62,839	749	96,895	42,293	1,239	45,340
Madagascar	1,209	-	1,410	1,200	-	1,341	400	-	527
Pakistan	248	-	317	-	-	42	-	-	19
Trinidad	166,349	1,227	197,349	59,195	-	62,104	55,642	-	58,555
All other	-	20,428	74,792	-	21,078	145,540	-	19,936	201,989
Total	903,305	682,485	1,804,208	762,221	763,019	1,889,741	708,478	864,444	1,980,269

FINANCIAL STATEMENT NOTES

Three months ended December 31, 2011

Segment	Natural gas, condensate and oil sales	Other income	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion expense	Exploration and evaluation expense	Gain on short-term investments	Other expense	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	14,422	-	(4,882)	-	(2,277)	(3,336)	(541)	-	-	-	-	-	3,386
India	70,697	-	(1,899)	(3,650)	(7,641)	(22,639)	(604)	-	-	-	-	(12,875)	21,389
Indonesia	-	6,453	-	-	-	-	(20,384)	-	-	-	-	-	(13,931)
Kurdistan	-	-	-	-	-	-	(607)	-	-	-	-	-	(607)
Madagascar	-	-	-	-	-	-	(292)	-	-	-	-	-	(292)
Pakistan	-	-	-	-	-	-	(1,025)	-	-	-	-	-	(1,025)
Trinidad	-	-	-	-	-	-	(33,314)	-	-	-	-	-	(33,314)
Canada	107	-	-	(6)	(198)	-	-	-	-	-	-	-	(97)
All other	-	-	-	-	-	-	(573)	2,384	(6,384)	(1,529)	(10,820)	1,008	(15,914)
Total	85,226	6,453	(6,781)	(3,656)	(10,116)	(25,975)	(57,340)	2,384	(6,384)	(1,529)	(10,820)	(11,867)	(40,405)

Three months ended December 31, 2010

Segment	Natural gas, condensate and oil sales	Other income	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion expense	Exploration and evaluation expense	Gain on short-term investments	Other expense	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	17,124	-	(5,787)	-	(2,319)	(3,258)	(322)	-	-	-	-	-	5,438
India	94,655	-	(2,031)	(4,857)	(8,453)	(21,475)	(975)	-	-	-	-	(348)	56,516
Indonesia	-	-	-	-	-	-	(11,487)	-	-	-	-	-	(11,487)
Kurdistan	-	-	-	-	-	-	(733)	-		-	-	-	(733)
Madagascar	-	-	-	-	-	-	(1,358)	-	-	-	-	-	(1,358)
Pakistan	-	-	-	-	-	-	(1,353)	-	-	-	-	-	(1,353)
Trinidad	-	-	-	-	-	-	(4,148)	-	-	-	-	-	(4,148)
Canada	133	-	-	(17)	(44)	-	-	-	-	-	-	-	72
All other	-	-	-	-	-	-	(167)	166	(6,590)	(2,144)	(8,859)	453	(17,141)
Total	111,912	-	(7,818)	(4,874)	(10,816)	(24,733)	(20,543)	166	(6,590)	(2,144)	(8,859)	105	25,806

Nine months ended December 31, 2011

Segment	Natural gas, condensate and oil sales	Other income	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion expense	Exploration and evaluation expense	Loss on short-term investments	Other expense	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	42,708	-	(14,459)	-	(5,998)	(9,185)	(933)	-	-	-	-	-	12,133
India	238,708	-	(5,136)	(12,191)	(22,981)	(74,416)	(1,146)	-	-	-	-	(88,015)	34,823
Indonesia	-	6,453	-	-	-	-	(47,815)	-	-	-	-	-	(41,362)
Kurdistan	-	-	-	-	-	-	(2,206)	-	-	-	-	-	(2,206)
Madagascar	-	-	-	-	-	-	(822)	-	-	-	-	-	(822)
Pakistan	-	-	-	-	-	-	(1,820)	-	-	-	-	-	(1,820)
Trinidad	-	-	-	-	-	-	(59,628)	-	-	-	-	-	(59,628)
Canada	254	-	-	(7)	(242)	-	-	-	-	-	-	-	5
All other	-	-	-	-	-	-	(2,240)	(6,184)	(34,269)	(5,544)	(33,202)	1,012	(80,427)
Total	281,670	6,453	(19,595)	(12,198)	(29,221)	(83,601)	(116,610)	(6,184)	(34,269)	(5,544)	(33,202)	(87,003)	(139,304)

Nine months ended December 31, 2010

Segment	Natural gas, condensate and oil sales	Other income	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion expense	Exploration and evaluation expense	Loss on short-term investments	Other expense	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	46,193	-	(15,584)	-	(5,964)	(8,799)	(505)	-	-	-	-	(6)	15,335
India	300,971	-	(6,246)	(16,059)	(21,813)	(67,608)	(2,529)	-	-	-	-	(1,567)	185,149
Indonesia	-	-	-	-	-	-	(39,067)	-	-	-	-	-	(39,067)
Kurdistan	-	-	-	-	-	-	(2,531)	-	-	-	-	-	(2,531)
Madagascar	-	-	-	-	-	-	(23,499)	-	-	-	-	-	(23,499)
Pakistan	-	-	-	-	-	-	(1,510)	-	-	-	-	-	(1,510)
Trinidad	-	-	-	-	-	-	(9,340)	-	-	-	-	-	(9,340)
Canada	464	-	-	(50)	(138)	-	-	-	-	-	-	-	276
All other	-	-	-	-	-	-	(539)	(13,504)	(18,533)	(6,306)	(22,798)	530	(61,150)
Total	347,628	-	(21,830)	(16,109)	(27,915)	(76,407)	(79,520)	(13,504)	(18,533)	(6,306)	(22,798)	(1,043)	63,663

25. Guarantees

(thousands of U.S. dollars)	As at December 31, 2011	As at March 31, 2011	As at April 1, 2010
Performance security guarantees included in restricted cash (1)			
Cauvery—India	-	804	804
D4—India	1,474	3,234	984
Indonesia	11,957	7,613	21,550
Performance security guarantees not included in restricted cash (2)			
Indonesia	2,454	2,454	2,454
Madagascar	-	-	1,178
Total guarantees	15,885	14,105	26,970

(1) The Company is required to provide funds to support the guarantees in the amounts indicated above.

(2) These performance security guarantees are not reflected on the balance sheet as they are supported by Export Development Canada. On May 5, 2012, the performance security guarantee will be up for renewal and the Company will be required to support the guarantee with cash.

The Company has performance security guarantees related to the capital commitments for exploration blocks. The guarantees are cancelled when the Company completes the work required under the exploration period.

26. Contingent Liabilities

a. During the year ended March 31, 2006, a group of petitioners in Bangladesh (the petitioners) filed a writ with the High Court Division of the Supreme Court of Bangladesh (the High Court) against various parties including Niko Resources (Bangladesh) Ltd. (NRBL), a subsidiary of the Company.

In November 2009, the High Court ruled on the writ. Both the Company and the petitioners have the right to appeal the ruling to the Supreme Court. The ruling can be summarized as follows:

Petitioner Request	**High Court Ruling**
That the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal.	The Joint Venture Agreement for Feni and Chattak fields is valid.
That the government realize from the Company compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area.	The compensation claims should be decided by the lawsuit described in note (b) below or by mutual agreement.
That Petrobangla withhold future payments to the Company relating to production from the Feni field ($27.9 million as at December 31, 2011).	Petrobangla to withhold future payments to the Company related to production from the Feni field until the lawsuit described in note (b) below is resolved or both parties agree to a settlement.
That all bank accounts of the Company maintained in Bangladesh be frozen.	The ruling did not address this issue, therefore the previous ruling stands. Funds in the Company's bank accounts maintained in Bangladesh cannot be repatriated pending resolution of the lawsuit described in note (b) below.

On January 7, 2010, NRBL requested an arbitration proceeding with the International Centre for the Settlement of Investment disputes (ICSID). The arbitration is between NRBL and three respondents: The People's Republic of Bangladesh; Bangladesh Oil, Gas & Mineral Corporation (Petrobangla); and Bangladesh Petroleum Exploration & Production Company Limited (Bapex). The arbitration hearing will attempt to settle all compensation claims described in this note and note (b). ICSID registered the request on May 24, 2010.

In June 2010, the Company filed an additional proceeding with ICSID to resolve its claims for payment from Petrobangla in accordance with the Gas Purchase and Sale Agreement with Petrobangla to receive all amounts for previously delivered gas.

b. During the year ended March 31, 2006, Niko Resources (Bangladesh) Ltd. received a letter from Petrobangla demanding compensation related to the uncontrolled flow problems that occurred in the Chattak field in January and June 2005. Subsequent to March 31, 2008, Niko Resources (Bangladesh) Ltd. was named as a defendant in a lawsuit that was filed in Bangladesh by Petrobangla and the Republic of Bangladesh demanding compensation as follows:

(i) taka 421,183,000 ($5.3 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;

(ii) taka 826,923,000 ($10.3 million) for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;

(iii) taka 845,560,000 ($10.5 million) for environmental damages, an amount subject to be increased upon further assessment;

(iv) taka 6,317,750,000 ($78.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and

(v) any other claims that arise from time to time.

ICSID has registered the request for arbitration of the issues indicated above as discussed in note 26(a). In addition, the Company will actively defend itself against the lawsuit, which may take an extended period of time to settle. Alternatively, the Company may attempt to receive a stay order on the lawsuit pending either a settlement and/or results of ICSID arbitration.

The Company believes that the outcome of the lawsuit and/or ICSID arbitration and the associated cost to the Company, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements. Settlement costs, if any, will be recorded in the period of determination.

c. In accordance with natural gas sales contracts to customers of production from the Hazira field in India, the Company had committed to deliver certain minimum quantities and was unable to deliver the minimum quantities for a period ending December 31, 2007. The Company's partner in the Hazira field delivered the shortfall volumes in return for either: (a) delivery of replacement volumes five times greater than the shortfall; (b) a cash payment; or (c) a combination of (a) and (b). The Company estimates the cash amount to settle the contingency at US$11 million. The Company believes that the agreement with it's partner is not effective as the Government of India's gas utilization policy prevents the Company from supplying the gas to the partner. The Company's partner has served a notice of arbitration as the Company is unable to supply gas from the D6 block to the partner and the arbitration process has commenced. The Company believes that the outcome is not determinable.

The Company may not be able to supply gas to a customer in Hazira whose contract runs until mid-2016. The Company had previously planned to supply gas from the D6 Block to the customer. Due to a change in the gas allocation policy by the Government of India, the Company may not be able to fulfill the contract with gas supply from the D6 Block. The Company has notified the customer that the underperformance of reservoir is a force majeure event. The customer does not agree with this position and has served a notice of arbitration on the Company. The Company believes that the outcome is not determinable.

d. The Company calculates and remits profit petroleum expense to the Government of India in accordance with the Production Sharing Contract. The profit petroleum expense calculation considers capital and other expenditures made by the joint interest, which reduce the profit petroleum expense. There are costs that the Company has included in the profit petroleum expense calculations that have been contested by the government. The Company believes that it is not determinable whether the above issue will result in additional profit petroleum expense. No amount has been recorded in these consolidated financial statements. Settlement costs, if any, will be recorded in the period of determination.

e. The Company has filed its income tax returns in India for the taxation years 1998 through 2008 under provisions that provide for a tax holiday deduction for eligible undertakings related to the Hazira and Surat fields.

The Company has received unfavourable tax assessments related to taxation years 1999 through 2007. The assessments contend that the Company is not eligible for the requested tax holiday because: a) the holiday only applies to "mineral oil" which excludes natural gas; and/or b) the Company has inappropriately defined undertakings.

In India, there are potentially four levels of appeal related to tax assessments: Commissioner Income Tax – Appeals ("CIT-A"); the Income Tax Appellate tribunal ("ITAT"); the High Court; and the Supreme Court. For taxation years 1999 to 2004, the Company has received favourable rulings at ITAT and the revenue Department has appealed to the High Court. For the 2005 taxation year, the Company has received a favourable ruling at CITA. For the 2006 and 2007 taxation years, the Company has appealed to CITA, however, CITA has agreed to wait for the High Court ruling on previous years prior to their ruling. The taxation years 2008 and later have not yet been assessed by the tax authorities.

In August 2009, the Government of India through the Finance (No.2) Act 2009 amended the tax holiday provisions in the Income Tax Act (Act). The amended Act provides that the blocks licensed under the NELP-VIII round of bidding and starting commercial production on or after April 1, 2009 are eligible for the tax holiday on production of natural gas. However, the budget did not address the issue of whether the tax holiday is applicable to natural gas production from blocks that have been awarded under previous rounds of bidding, which includes all of the Company's Indian blocks. The Company has previously filed and recorded its income taxes on the basis that natural gas will be eligible for the tax holiday.

With respect to "undertakings" eligible for the tax holiday deduction, the Act was amended to include an "explanation" on how to determine undertakings. The Act now states that all blocks licensed under a single contract shall be treated as a single undertaking. The "explanation" is described in the amendment as having retrospective effect from April 1, 2000. Since tax holiday provisions became effective April 1, 1997, it is unclear as to why the "explanation" has effect from April 1, 2000. The Hazira production sharing contract (PSC) was signed in 1994 and commenced production prior to April 1, 2000. As a result, the Company is unable to apply the amended definition of "undertaking" to the Hazira PSC. The Company has previously filed and recorded its income taxes for the taxation years of 1999 to 2008 on the basis of multiple undertakings for the Hazira and Surat PSC.

The Company will continue to pursue both issues through the appeal process. The Company has challenged the retrospective amendments to the undertakings definition and the lack of clarification of whether natural gas is eligible for the tax holiday with the Gujarat High Court. The Company was granted an interim relief by the High Court on March 12, 2010 instructing the Revenue Department to not give effect to the "explanation" referred to above retrospectively until the matter is clarified in the courts. Even if the Company receives favourable outcomes with respect to both issues discussed above, the Revenue Department can challenge other aspects of the Company's tax filings.

For the taxation years ended March 31, 2009 through March 31, 2011, the Company has filed its tax return assuming natural gas is eligible for the tax holiday at Hazira and Surat but, unlike all previous years, has filed its tax return based on Hazira and Surat each having a single undertaking. The Company has reserved its right, under Indian tax law, to claim the tax holiday with multiple undertakings. While the Company still believes that it is eligible for the tax holiday on multiple undertakings, the change in method of filing is because the legislative changes, referred to above, lead to ambiguity in the Act. More specifically, if the Company had filed its return in a manner that is deemed to be in violation of the current legislation, the Company can be liable for interest and penalties. Further, at the time of filing the 2009 and 2010 tax returns, the Company had not appealed the amendments brought out in the tax holiday provisions and did not have the benefit of the interim relief by the High Court. As a result, the Company has filed in a more conservative manner than its interpretation of tax law as described previously. Despite filing in a conservative manner, the Company will continue to pursue the tax holiday changes through the appeals process.

Should the High Court overturn the rulings previously awarded in favour of the Company by the Tribunal court, and the Company either decides not to appeal to the Supreme Court or appeals to the Supreme Court and is unsuccessful, the Company would have to accordingly change its tax position and record a tax expense of approximately $56 million (comprised of additional taxes of $33 million and write off of approximately $23 million of the net income tax receivable). In addition, the Company could be obligated to pay interest on taxes for the past periods.

f. In December 2009, the arbitration of ownership of a 36-inch pipeline that is connected to the Hazira facilities in India was ruled in favor of the Company and its joint venture partner. The Government of India has filed a writ with the High Court in Delhi challenging the arbitration decision. The High Court has set a hearing date. If the appeal is heard and the court rules against the Company and its joint venture partner, the Company may challenge the decision in the Supreme Court of India. Adverse resolution would result in the write-off of long-term accounts receivable of $3 million and record a payable of $3 million.

g. The Cauvery Block in India is under relinquishment. The Company believes it has fulfilled all commitments for the block while the Government of India contends that the Company has unfulfilled commitments of up to approximately $2 million. The Company believes the outcome is currently not determinable.

27. Reconciliations from Canadian GAAP to IFRS

The Company adopted IFRS effective April 1, 2010 and is presenting its opening statement of financial position on transition to IFRS as at April 1, 2010. The Company's accounting policies under IFRS, as outlined in note 2, differ from those followed under previous GAAP. These accounting policies have been applied for the three and nine months ended December 31, 2011, as well as to the opening statement of financial position on the transition date, April 1, 2010, the comparative information for the three and nine months ended December 31, 2010 and the comparative information for the year ended March 31, 2011.

The adjustments arising from the application of IFRS to amounts on the statement of financial position on the transition date and on transactions prior to that date, were recognized as an adjustment to the Company's opening deficit category on the statement of financial position when appropriate.

On transition to IFRS on April 1, 2010, the Company used certain exemptions allowed under IFRS 1 "First Time Adoption of International Reporting Standards". IFRS 1 indicates that a first-time adopter may elect not to apply IFRS 3 Business Combinations retrospectively to business combinations that occurred before the date of transition to IFRS. The Company has taken advantage of this exemption and has applied IFRS 3 only to business combinations that occurred on or after April 1, 2010.

There were no material adjustments to the Company's cash flows on transition from Canadian GAAP to IFRS.

Reconciliation of consolidated statement of financial position:

(thousands of U.S. dollars)	March 31, 2011 Canadian GAAP	March 31, 2011 Adjustment	March 31, 2011 IFRS	December 31, 2010 Canadian GAAP	December 31, 2010 Adjustment	December 31, 2010 IFRS	April 1, 2010 Canadian GAAP	April 1, 2010 Adjustment	April 1, 2010 IFRS
Assets									
Current assets									
Cash and cash equivalents	108,342	-	108,342	69,935	-	69,935	196,813	-	196,813
Restricted cash	7,704	-	7,704	17,538	-	17,538	28,245	-	28,245
Account receivable (notes a, b, c, d, l, m)	72,422	2,738	75,160	80,232	(408)	79,824	47,706	(3,408)	44,298
Short-term investments	14,922	-	14,922	18,541	-	18,541	32,081	-	32,081
Inventory	363	6,849	7,212	261	11,674	11,935	256	6,999	7,255
Prepaid expenses / deposits (note b)	1,566	(1,566)	-	1,640	(1,640)	-	724	(724)	-
	205,319	8,021	213,340	188,147	9,626	197,773	305,825	2,867	308,692
Restricted cash	10,232	-	10,232	8,616	-	8,616	21,026	-	21,026
Long-term accounts receivable (notes d, l)	50,076	(3,527)	46,549	29,436	(2,272)	27,164	31,128	(1,208)	29,920
Long-term investment	2,830	-	2,830	2,704	-	2,704	-	-	-
Exploration and evaluation assets	-	762,221	762,221	-	747,818	747,818	-	708,478	708,478
Property, plant and equipment (notes d, e, f, g, h, i, j, l, m)	1,861,442	(1,098,423)	763,019	1,874,361	(1,080,640)	793,721	1,844,826	(980,382)	864,444
Income tax receivable (note a)	34,637	110	34,747	25,400	2,950	28,350	23,240	4,059	27,299
Deferred tax assets (note d)	42,977	13,826	56,803	52,170	-	52,170	20,410	-	20,410
	2,207,513	(317,772)	1,889,741	2,180,834	(322,518)	1,858,316	2,246,455	(266,186)	1,980,269
Liabilities									
Current liabilities									
Accounts payable (note a, d, l, m)	90,340	(3,035)	87,305	83,404	(1,268)	82,136	123,547	(1,737)	121,810
Current tax payable (note a)	2,277	74	2,351	2,276	279	2,555	1,971	101	2,072
Finance lease obligation (note h)	5,848	(1,044)	4,804	5,721	(1,710)	4,011	5,357	(1,079)	4,278
Borrowings	-	-	-	-	-	-	154,811	-	154,811
	98,465	(4,005)	94,460	91,401	(2,699)	88,702	285,686	(2,715)	282,971
Decommissioning obligations (note j)	37,703	(6,249)	31,454	33,103	(4,437)	28,666	30,520	(3,403)	27,117
Finance lease obligation (note h)	52,624	(4,149)	48,475	54,098	(3,751)	50,347	58,472	(5,194)	53,278
Borrowings	-	-	-	-	-	-	38,003	-	38,003
Deferred tax liabilities (note a)	227,746	-	227,746	227,746	-	227,746	227,746	-	227,746
Convertible debentures	309,221	-	309,221	300,901	-	300,901	291,063	-	291,063
	725,759	(14,403)	711,356	707,249	(10,887)	696,362	931,490	(11,312)	920,178
Shareholders' equity									
Share capital (note j)	1,157,889	4,430	1,162,319	1,145,751	4,430	1,150,181	1,107,163	4,430	1,111,593
Contributed surplus (note j)	67,279	(4,242)	63,037	62,631	(4,036)	58,595	48,397	(3,320)	45,077
Equity component of convertible debentures	14,765	-	14,765	14,765	-	14,765	14,765	-	14,765
Accumulated other comprehensive income (notes e, j)	422	(8,766)	(8,344)	6,480	(11,649)	(5,169)	12,220	(11,036)	1,184
Retained earnings (deficit) (note n)	241,399	(294,791)	(53,392)	243,958	(300,376)	(56,418)	132,420	(244,948)	(112,528)
	1,481,754	(303,369)	1,178,385	1,473,585	(311,631)	1,161,954	1,314,965	(254,874)	1,060,091
	2,207,513	(317,772)	1,889,741	2,180,834	(322,518)	1,858,316	2,246,455	(266,186)	1,980,269

Reconciliation of consolidated statement of comprehensive income:

(thousands of U.S. dollars)	Year ended March 31, 2011 Canadian GAAP	Adjustment	IFRS	Three months ended December 31, 2010 Canadian GAAP	Adjustment	IFRS	Nine months ended December 31, 2010 Canadian GAAP	Adjustment	IFRS
Oil and natural gas revenue	453,824	-	453,824	111,912	-	111,912	347,628	-	347,628
Royalties	(20,707)	-	(20,707)	(4,874)	-	(4,874)	(16,109)	-	(16,109)
Profit petroleum (note d)	(29,261)	-	(29,261)	(7,818)	-	(7,818)	(21,830)	-	(21,830)
Production and operating expenses (notes h, j, k, l)	(38,360)	(75)	(38,435)	(10,862)	46	(10,816)	(28,261)	346	(27,915)
Depletion expense (note g)	(134,694)	25,510	(109,184)	(30,764)	6,031	(24,733)	(94,715)	18,308	(76,407)
Exploration and evaluation (notes e, j, k)	-	(97,081)	(97,081)	-	(20,574)	(20,574)	-	(79,551)	(79,551)
(Loss) / gain on short-term investments	(12,720)	-	(12,720)	166	-	166	(13,504)	-	(13,504)
Other expenses	(9,861)	385	(9,476)	-	-	-	-	-	-
General and administrative expenses (notes e, k)	(11,972)	1,163	(10,809)	(2,885)	772	(2,113)	(6,977)	702	(6,275)
Share-based payment expense (note j)	(28,998)	6,967	(22,031)	(7,461)	1,640	(5,821)	(21,359)	4,986	(16,373)
Depreciation (note g)	(2,410)	(771)	(3,181)	(610)	(159)	(769)	(1,672)	(488)	(2,160)
Operating profit	164,841	(63,902)	100,939	46,804	(12,244)	34,560	143,201	(55,697)	87,504
Finance income (notes d, k)	912	1,468	2,380	540	108	648	(64)	1,191	1,127
Finance expense									
Interest expense (note h)	(24,928)	(1,003)	(25,931)	(6,719)	(268)	(6,987)	(23,168)	(914)	(24,082)
Accretion expense (note i)	(6,904)	57	(6,847)	(543)	17	(526)	(1,586)	39	(1,547)
Foreign exchange gain / (loss) (notes a, m)	875	90	965	(1,893)	(67)	(1,960)	1,751	79	1,830
Other	-	(379)	(379)	-	(34)	(34)	-	(126)	(126)
Net finance expense	(30,045)	233	(29,812)	(8,615)	(244)	(8,859)	(23,067)	269	(22,798)
Income before income taxes	134,796	(63,669)	71,127	38,189	(12,488)	25,701	120,134	(55,428)	64,706
Income tax expense									
Current tax (expense) (note a)	(36,900)	35,407	(1,493)	(8,959)	9,064	105	(32,215)	31,172	(1,043)
Minimum alternate tax (expense) (note a)	-	(35,407)	(35,407)	-	(9,064)	(9,064)	-	(31,172)	(31,172)
Deferred tax reduction (note a)	21,844	13,826	35,670	9,064	-	9,064	31,172	-	31,172
	(15,056)	13,826	(1,230)	105	-	105	(1,043)	-	(1,043)
Net income	119,740	(49,843)	69,897	38,294	(12,488)	25,806	119,091	(55,428)	63,663
Foreign currency translation (loss) / gain	(11,798)	2,270	(9,528)	(8,324)	97	(8,227)	(5,740)	(613)	(6,353)
Comprehensive income	107,942	(47,573)	60,369	29,970	(12,391)	17,579	113,351	(56,041)	57,310

Notes to reconciliations:

a. Income taxes

The book value of property, plant and equipment related to the D6 Block is less under IFRS than under Canadian GAAP. This results in an increase in the deferred tax asset.

Under Canadian GAAP, the Company classified excess tax instalments as accounts receivable and have classified the same as income tax receivable under IFRS. This resulted in a $4.4 million adjustment as at April 1, 2010.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase / (decrease) in accounts receivable	-	(2,887)	(4,429)
Increase in income tax receivable	110	2,950	4,059
Increase in deferred tax asset	13,826	-	-
(Increase) / decrease in accounts payable	(48)	270	414
(Increase) in current tax payable	(74)	(279)	(101)
(Increase) / decrease in deficit	13,814	54	(57)

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
Increase in foreign exchange gain	45	111
Decrease in deferred tax reduction	13,826	-
Decrease in current income tax expense	35,407	31,172
Increase in minimum alternate tax expense	(35,407)	(31,172)
(Decrease) / increase in comprehensive income	13,871	111

b. Prepaid Expenses / Deposits

Prepaid expenses and deposits have been reclassified to accounts receivable.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase in accounts receivable	1,566	1,640	724
(Decrease) in prepaid expenses / deposits	(1,566)	(1,640)	(724)
(Increase) / decrease in deficit	-	-	-

c. Cash calls receivable

Cash calls receivable from joint venture partners are classified as current assets as they are due in the current period. Under Canadian GAAP, these were misclassified as long-term accounts receivable.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase in accounts receivable	638	-	-
(Decrease) in long-term accounts receivable	(638)	-	-
(Increase) / decrease in deficit	-	-	-

d. 36” Pipeline

Accounts receivable and payable related to the 36” pipeline in Hazira reported under Canadian GAAP were net under IFRS as the amounts are expected to be settled net with the Company’s joint venture partner. In addition, there were adjustments related to the audit of the results from the 36” pipeline.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
(Decrease) / increase in accounts receivable	-	-	1,441
(Decrease) in long-term accounts receivable	(2,889)	(2,272)	(1,208)
Decrease / (increase) in accounts payable	2,889	2,272	(233)
(Increase) / decrease in deficit	-	-	-

e. Property, plant and equipment

Under Canadian GAAP, the Company followed the full-cost method of accounting capitalizing costs incurred for exploration, development and producing properties. Under the Company’s selected IFRS policies, pre-license costs, geological and geophysical costs (G&G), the costs of unsuccessful exploration drilling and associated general and administrative costs (G&A) are expensed. The remaining capital assets previously categorized as property, plant and equipment have considered under the IFRS categories including inventory and exploration and evaluation assets.

Under Canadian GAAP, cumulative translation differences arose on the revaluation of assets and liabilities to the reporting currency. The cumulative translation change under IFRS is a result of the adjustment of historical differences associated with assets that were written off, impaired or adjusted in property, plant and equipment.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase in inventory	6,849	11,674	6,981
Increase in exploration and evaluation assets	762,221	747,818	708,478
Decrease in property, plant and equipment	(1,158,580)	(1,135,900)	(1,018,428)
Decrease in accumulated other comprehensive income	8,920	11,425	11,036
(Increase) / decrease in deficit	(380,590)	(364,983)	(291,933)

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
(Increase) in exploration and evaluation expense	(88,657)	(73,050)
(Decrease) / increase in comprehensive income	(88,657)	(73,050)

f. Impairment

Impairment tests were calculated on transition to IFRS for each cash-generating unit. The cash-generating unit comprised of Feni and Chattak properties in Bangladesh and the cash-generating unit comprised of the Cauvery property in India were impaired. These properties were included in property, plant and equipment under Canadian GAAP. Under Canadian GAAP, the impairment test was considered on a country-by-country basis. Under IFRS, the impairment test is considered at the cost-generating-unit level, which is the PSC for Cauvery and the JVA for Feni and Chattak and does not include the Company’s other properties in India or Bangladesh. The fair value of the properties used in the assessment of the impairment was the value in use and neither property had reserves attributable to it.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
(Decrease) in property, plant and equipment	(73,407)	(73,407)	(73,407)
(Increase) / decrease in deficit	(73,407)	(73,407)	(73,407)

g. Accumulated depletion

Under Canadian GAAP, depletion related to producing properties was calculated for each cost centre, which was defined as a country. IFRS requires depletion to be calculated based on individual components, which the Company has determined to be a production sharing contract (PSC). An adjustment was made for the change in the cost base as a result of the accounting policies for exploration and evaluation costs selected by the Company.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase in property, plant and equipment	150,318	143,014	125,194
(Increase) / decrease in deficit	150,318	143,014	125,194

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
Decrease in depletion expense	25,510	18,308
(Increase) in depreciation expense	(771)	(488)
Decrease in other expense	385	-
(Decrease) / increase in comprehensive income	25,124	17,820

h. Lease

Under Canadian GAAP and IFRS, the finance lease obligation is recorded at inception of the lease for an amount that is the lesser of the present value of the minimum lease payments and the fair value of the asset. Under Canadian GAAP, the present value of the minimum lease payments is calculated using the lesser of the rate implicit of 11.7% in the lease and the Company's incremental cost of borrowing at the time of 6% while the rate implicit in the lease is always used under IFRS. As a result, the lease obligation was recorded at the fair value under Canadian GAAP and is recorded at the present value of the minimum lease payments under IFRS.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
(Decrease) in property, plant and equipment	(6,217)	(6,056)	(6,104)
Decrease in current portion of finance lease obligation	1,044	1,710	1,079
Decrease in non-current portion of finance lease obligation	4,149	3,751	5,194
(Increase) / decrease in deficit	(1,024)	(595)	169

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
Decrease in production and operating expense	-	163
(Increase) in interest expense	(1,193)	(927)
(Decrease) / increase in comprehensive income	(1,193)	(764)

i. Decommissioning obligations

Under Canadian GAAP asset retirement obligations were discounted at the corporate credit adjusted risk free rate of 5 to 7 percent over time. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted and applied by country therefore the provision is discounted at an average risk free rate of 7 percent resulting in a decrease in the decommissioning obligations and property, plant and equipment.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
(Decrease) in property, plant and equipment	(5,924)	(4,130)	(3,135)
Decrease in decommissioning obligations	6,249	4,437	3,403
(Increase) / decrease in deficit	325	307	268

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
Decrease in accretion expense	57	39
(Decrease) / increase in comprehensive income	57	39

j. Share-based payments

Under Canadian GAAP, the Company recognized an expense related to the share-based payments (SBP) for options granted after March 31, 2003. On transition to IFRS, the Company applied IFRS2 retrospectively and recognized the cost for share-based payments vesting after April 1, 2005 as an expense. This resulted in an additional share-based payment expense increasing the deficit and increasing share capital as these stock options have been exercised and the associated expense has been moved to share capital.

Under Canadian GAAP, the Company recognized an expense related to share-based payments, however, did not incorporate a forfeiture multiple. Under IFRS, the Company is required to estimate a forfeiture rate. The share-based payments recognized under Canadian GAAP were adjusted to incorporate a forfeiture rate resulting in a decrease in the deficit and a decrease in contributed surplus.

Under Canadian GAAP, the Company capitalized the portion of share-based payments attributable to exploration activities. Under IFRS, the Company expensed the majority of share-based payments. This resulted in a decrease in property, plant and equipment and an increase in the deficit.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
(Decrease) in property, plant and equipment for capitalized share-based payments	(5,913)	(6,115)	(4,502)
(Increase) in share capital	(4,430)	(4,430)	(4,430)
Decrease in contributed surplus	4,242	4,036	3,320
(Increase) / decrease in accumulated other comprehensive income	(154)	224	-
(Increase) / decrease in deficit	(6,255)	(6,285)	(5,612)

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
(Increase) in production and operating expense	(1,776)	(1,234)
(Increase) in exploration and evaluation expense	(5,834)	(4,425)
Decrease in share-based payment expense	6,967	4,986
Increase / (decrease) in comprehensive income	(643)	(673)

k. Reclassification of the income statement according to function

The Company classifies the statement of comprehensive income according to the function of the costs. The costs incurred are booked into the categories of production and operating expense, exploration and evaluation expense and general and administrative expense dependant on the activities to which they relate. As a result, a number of the costs recorded in one category under Canadian GAAP were reclassified to another category under IFRS.

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010
Decrease in production and operating expense	1,431	1,568
(Increase) in exploration and evaluation expense	(2,590)	(2,076)
Decrease in general and administrative expense	1,163	621
Increase in net finance income	189	-
(Increase) in net finance expense	(193)	(113)
Increase / (decrease) in comprehensive income	-	-

l. Other

The Company had other individually insignificant adjustments from Canadian GAAP to IFRS as follows:

Consolidated statement of financial position	March 31, 2011	Dec. 31, 2010	April 1, 2010
Increase / (decrease) in accounts receivable	534	839	(1,144)
Increase / (decrease) in inventory	-	-	18
Increase in property, plant and equipment	1,300	1,954	-
Decrease / (increase) in accounts payable	194	(1,274)	1,556
(Increase) / decrease in deficit	2,028	1,519	430

Consolidated statement of comprehensive income	March 31, 2011	Dec. 31, 2010
Decrease / (increase) in production and operating expenses	270	(151)
Decrease in general and administrative expenses	-	81
Increase in finance income	1,279	1,191
Decrease / (increase) in finance expense	49	(32)
Decrease / (increase) in comprehensive income	1,598	1,089

m. Deficit

The following is a summary of adjustments to the deficit:

Note	Description	March 31, 2011	Dec. 31, 2010	April 1, 2010
a	Reclassification of tax amounts	13,814	54	(57)
d	36” pipeline adjustments	-	-	-
e	Write-off of exploration and evaluation costs and associated general and administrative costs	(380,590)	(364,983)	(291,933)
f	Impairment of property, plant and equipment	(73,407)	(73,407)	(73,407)
g	Decrease in accumulated depletion as a result of calculating depletion expense on a cash-generating unit basis as opposed to a cost centre	150,318	143,014	125,194
h	Adjustment related to initial value recorded for the lease of the floating, production, storage and offloading vessel	(1,024)	(595)	169
i	Adjustment to rate used to discount decommissioning obligations	325	307	268
j	Adjustment for commencement of share-based payments, expensing all share-based payments and including a forfeiture rate in the calculation of share-based payments	(6,255)	(6,285)	(5,612)
l	Other miscellaneous adjustments	2,028	1,519	430
	(Increase) / decrease in deficit	(294,791)	(300,376)	(244,948)

CORPORATE INFORMATION

OFFICERS AND DIRECTORS
Edward S. Sampson
Chairman of the Board, President and
Chief Executive Officer

Murray Hesje
VP Finance and Chief Financial Officer

William T. Hornaday, B.Sc., P.ENG.
Chief Operating Officer, Director

C.J. (Jim) Cummings, LLB
Director

Conrad P. Kathol, B.Sc., P.ENG.
Director

Wendell W. Robinson, BBA, MA, CFA
Director

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Symbol: NKO

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