Q2 INTERIM REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2012

NIKO REPORTS RESULTS FOR THE QUARTER ENDED SEPTEMBER 30, 2012

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 six month periods ended September 30, 2012. The operating results are effective November 13, 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

The Company has made significant progress on its options for the repayment of its convertible debentures that mature on December 30, 2012. Discussions are at an advanced stage and the Company expects resolution well in advance of maturity.

Niko's strategy has been to acquire a large number of PSCs in emerging exploration trends, use advanced technology to develop a geologically and geographically diverse portfolio of high impact wells, execute leveraged farm-outs, and target partners with worldwide deep water experience. Seismic has been acquired over the vast majority of Niko's exploration acreage and the Company has been successful in farming out blocks and is continuing to work on additional leveraged farm-outs to world-class partners.

It appears to management that the market has greatly overreacted to the initial results of the Company's drilling campaign in Indonesia. The Company has drilled the equivalent of one net well out of a multi-year drilling program. By taking a portfolio approach, Niko will benefit from economies of scale in drilling operations as well as increase the statistical likelihood of success. A number of changes made by Niko for the Ocean Monarch rig being used in the deepwater drilling campaign in Indonesia have and will result in significant time and cost savings for the Company. These changes, coupled with leveraged farm-outs, will provide shareholders with exposure to significant exploration potential at relatively low cost.

Niko also announces that Glen Valk, Niko's Corporate Treasurer, will succeed Murray Hesje as Vice President, Finance and Chief Financial Officer of the Company upon Mr. Hesje's retirement effective at year end. Mr. Valk has over 25 years of finance experience with international E&P companies in Canada, Indonesia and the United States. Mr. Valk joined the Company in August 2012 and has been working with Mr. Hesje to ensure a smooth transition takes place. Mr. Hesje joined Niko in July 2006 and has been instrumental in the Company's growth into new regions such as Indonesia and Trinidad. Importantly, upon his retirement, Mr. Hesje will continue with Niko as a special advisor to the Company and the Board of Directors.

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

REVIEW OF OPERATIONS AND GUIDANCE

Sales Volumes

	Three months ended Sept 30,		Six months ended Sept 30	
	2012	2011	2012	2011
(MMcfe/d)	Actual	Actual	Actual	Actual
D6 Block, India	106	169	113	175
Block 9, Bangladesh	59	61	60	59
Others[(1)]	7	10	7	10
Total production[(2)]	173	241	181	244

[(1)] Others includes Hazira and Surat in India, and Canada.
[(2)] Figures may not add up due to rounding.

Total sales volumes for the second quarter averaged 173 MMcfe/d compared to 189 MMcfe/d for the first quarter, primarily due to anticipated natural declines in the D6 Block in India without any remedial work being done in the period.

As indicated in the Company's press release of October 19, 2012, production for the full year ended March 31, 2013 is forecast to be 168 MMcfe/d, four percent lower than the Company's previous guidance of 175 MMcfe/d, due to temporary mechanical constraints in Block 9 in Bangladesh. This decrease is expected to reduce oil and gas revenue by approximately $2 million for the full year ended March 31, 2013.

Funds from Operations

	Three months ended Sept 30,		Six months ended Sept 30,	
	2012	2011	2012	2011
(millions of U.S. dollars)	Actual	Actual	Actual	Actual
Funds from operations	34	61	75	121

As with sales volumes, the primary reason for the variances in funds from operations relates to production from the D6 Block in India.

Capital Expenditures, net of Proceeds of Farm-outs and Other Arrangements

(millions of U.S. dollars)	Three months ended Sept 30, 2012	Six months ended Sept 30, 2012
Indonesia	12	48
Trinidad	25	44
All other	1	4
Total	38	96

Capital additions and expensed exploration spending, net of proceeds of farm-outs and other arrangements, totalled $38 million for the second quarter. Spending related primarily to exploration wells, seismic, other exploration projects, and branch office costs in Indonesia and Trinidad and Tobago. In addition, the Company recorded proceeds of farm-outs of an estimated $9 million, received $36 million from a former partner in exchange for assuming the partner's obligations for future drilling commitments and recorded costs related to pre-drilling activities and drilling inventory to prepare for the upcoming multi-year drilling campaign in Indonesia using the Ocean Monarch drilling rig.

The Company's guidance on its capital program for the year ended March 31, 2013, net of proceeds of negotiated farm-outs and other arrangements, has been revised from $210 million to $170 million, due primarily to deferrals of development spending. In addition, Niko has funded and will continue to fund certain drilling inventory and other costs related to its drilling program in future years. Total spending for the year is expected to be approximately $205 million.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis is a review of the Company's financial condition and results of operations as at and for the three and six months ended September 30, 2012. The Company's financial statements are prepared in accordance with International Reporting Standards ("IFRS") and all amounts are in thousands of United States dollars unless specified otherwise. This discussion should be read in conjunction with the audited consolidated financial statements for the year ended March 31, 2012. This MD&A is effective November 13, 2012. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

The term "the quarter" or "the period" used throughout this Management's Discussion and Analysis (MD&A) of Financial Condition and Results of Operations and in all cases refers to the period from July 1, 2012 through September 30, 2012. The term "prior year's quarter" or "prior year's period" used throughout this MD&A for comparative purposes and refers to the period from July 1, 2011 through September 30, 2011.

The Company's fiscal year is the 12-month period ended March 31. The terms "Fiscal 2012" and "prior year" is used throughout this MD&A and in all cases refers to the period from April 1, 2011 through March 31, 2012. The terms "Fiscal 2013", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2012 through March 31, 2013.

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. A 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.

Cautionary Statement Regarding Forward-Looking Statements and Information

Certain statements in this MD&A are "forward-looking statements" or "forward-looking information" within the meaning of applicable securities laws, herein "forward looking statements" or "forward looking information". Forward-looking information is frequently characterized by words such as "plan," "expect," "project," "intend," "believe," "anticipate," "estimate," "scheduled," "potential" or other similar words, or statements that certain events or conditions "may," "should" or "could" occur. Forward-looking information is based on the Company's expectations regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward-looking information reflects the Company's current beliefs and assumptions and is based on information currently available to it. Forward-looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the Company's ability to access sufficient capital from internal and external sources, the risks discussed under "Risk Factors" and elsewhere in this report and in the Company's public disclosure documents, and other factors, many of which are beyond its control. Although the forward-looking information contained in this report is based upon assumptions which the Company believes to be reasonable, it cannot assure investors that actual results will be consistent with such forward-looking information. Such forward-looking information is presented as of the date of this MD&A, and the Company assumes no obligation to update or revise such information to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward-looking information, you should not place undue reliance on this forward-looking information. See also "Risk Factors."

Specific forward-looking information contained in this MD&A may include, among others, statements regarding:

- the performance characteristics of the Company's oil, NGL and natural gas properties;
- oil, NGL and natural gas production levels, sales volumes and revenue;
- the size of the Company's oil, NGL and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil, NGL and natural gas;
- the Company's ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- debt and liquidity levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws;
- work commitments and capital expenditure programs;
- the Company's future development and exploration activities and the timing of these activities;
- the Company's future ability to satisfy certain contractual obligations;
- future economic conditions, including future interest rates;
- the impact of governmental controls, regulations and applicable royalty rates on the Company's operations;
- the completion of the Offering and uses of proceeds to be received from the Offering;
- the Company's expectations regarding the development and production potential of its properties;
- the Company's expectations regarding the costs for development activities;
- the resolution of various legal claims raised against the Company;
- the potential for asset impairment and recoverable amounts of such assets; and
- changes to accounting estimates and accounting policies.

The forward-looking statements contained in this MD&A are based on certain key expectations and assumptions made by us, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labor and services. Although the Company believes that the expectations reflected in the forward-looking statements in this MD&A are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and natural gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation, as well as the other risk factors identified under "Risk Factors" herein. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. You are cautioned that the foregoing list of factors and risks is not exhaustive.

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 its reserve reports.

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.

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.

The Company discloses the nature and timing of expected future events based on 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 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 update reserve estimates on an annual basis. See "Risk Factors" for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report. The information contained in this report, including the information provided under the heading "Risk Factors," identifies additional factors that could affect the Company's operating results and performance. The Company urges you to carefully consider those factors and the other information contained in this report.

The forward-looking statements contained in this report are made as of the date hereof and, unless so required by applicable law. The Company undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this report are expressly qualified by this cautionary statement.

Non-IFRS Measures

The selected financial information presented throughout this MD&A is prepared in accordance with IFRS, except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback", "segment profit" and "working capital". These non-IFRS financial measures, which have been derived from financial statements and applied on a consistent basis, are used by management as measures of performance of the Company. These non-IFRS measures should not be viewed as substitutes for measures of financial performance presented in accordance with IFRS or as a measure of a company's profitability or liquidity. 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.

The Company examined funds from operations to assess 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.

The Company examined operating netback, funds from operations netback, earnings netback and segment profit 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 is a measure of 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.

OVERALL PERFORMANCE

Funds from Operations

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Oil and natural gas revenue	58,080	86,810	113,179	175,088
Other income	311	-	311	-
Production and operating expenses	(9,696)	(9,057)	(17,574)	(18,088)
General and administrative expenses	(2,266)	(1,857)	(4,323)	(4,015)
Net finance expense	(6,081)	(5,588)	(12,165)	(11,389)
Realized foreign exchange loss	(2,833)	(3,217)	(2,480)	(3,368)
Current income tax recovery / (expense)	(285)	(1,183)	2,091	(4,290)
Minimum alternate tax expense	(3,125)	(4,917)	(4,410)	(12,797)
Funds from operations (1)	34,105	60,991	74,629	121,141

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

Oil and natural gas revenue during the three months ended September 30, 2012 decreased $29 million compared to the prior year's quarter. Oil and natural gas revenue during the six months ended September 30, 2012 decreased $62 million compared to the prior year's period. These decreases were primarily due to lower natural gas and crude oil sales from the D6 Block along with an adjustment to profit petroleum expense at the Hazira Field recorded in the first quarter of fiscal 2013.

Sales volumes from the D6 Block were 106 MMcfe/d and 113 MMcfe/d in the quarter and year-to-date period, respectively compared to 169 MMcfe/d and 175 MMcfe/d in the prior year's quarter and year-to-date period, respectively. The Company expects decline in production from the D6 Block to continue unless incremental production volume is added from new fields in the D6 Block.

An additional $6 million of profit petroleum expense for the Hazira Field reduced oil and natural gas revenue in the first quarter of fiscal 2013. The adjustment to profit petroleum expense was the result of a court ruling finding that the 36-inch natural gas sales pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery. There was a current income tax recovery of $2 million as a result of this adjustment to profit petroleum expense, which is deductible for tax purposes.

The Indian rupee strengthened against the US dollar during the quarter and year to date. As a result, there was a realized foreign exchange loss during the quarter due to revaluing Indian rupee based accounts payable to US dollars.

Minimum alternate tax expense is calculated on accounting income from the D6 Block. Higher depletion rates reduced accounting income and minimum alternate tax expense.

Net Income (Loss)

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Funds from operations (non-IFRS measure)	34,105	60,991	74,629	121,141
Production and operating expenses	(330)	(493)	(637)	(1,017)
Depletion and depreciation expense	(39,204)	(27,778)	(81,616)	(58,969)
Exploration and evaluation expense	(52,879)	(45,117)	(89,300)	(59,270)
Loss on short-term investments	(32)	(9,783)	(276)	(8,568)
Asset (impairment) / recovery	181	-	(38,919)	69
Share-based compensation expense	(3,342)	(6,511)	(6,902)	(12,698)
Finance expense	(2,162)	(1,951)	(4,158)	(3,750)
Unrealized foreign exchange (loss) / gain	6,657	(3,964)	1,512	(3,875)
Deferred income tax (expense) / recovery	28,433	4,603	24,971	(184)
	(28,573)	(30,003)	(120,696)	(27,121)
Change in accounting estimate—deferred taxes	-	-	-	(57,865)
Other expenses – impact of option cancellation	-	(13,913)	-	(13,913)
Net loss	(28,573)	(43,916)	(120,696)	(98,899)

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

Depletion and depreciation expense for the D6 Block for the quarter increased by $10 million to $35 million as a result of the revision to the reserve volumes and future costs included in the March 31, 2012 reserve report. This amount was partially offset by the effect of lower production.

Exploration and evaluation expense of $52 million for the quarter is comprised of: $35 million for costs associated with three unsuccessful exploration wells, $7 million for seismic and other exploration projects, $1 million for payments that are specified in the various PSC, $4 million for branch office costs for all exploration properties and $2 million for new venture activities. Exploration and evaluation expense of $36 million for the first quarter of fiscal 2013 included: $12 million for costs associated with one unsuccessful exploration well, $12 million for seismic and other exploration projects, $5 million for payments that are specified in the various PSC, $5 million for branch office costs for all exploration properties and $2 million for new venture activities.

The loss on short term investments is a result of mark to market valuation of these investments.

The Company recognized an asset impairment of $39 million in the first quarter of fiscal 2013 when it reassessed the recoverable amount of the Qara Dagh Block exploration and evaluation asset in Kurdistan.

Share-based compensation expense for the quarter and year-to-date decreased by $3 million and $6 million respectively, as a result of a decrease in the fair value per stock option granted as a result of lower stock price during the quarter as compared to the prior year’s quarter.

The Indian Rupee strengthened against the U.S. dollar during the quarter and year-to-date. As a result, there was an unrealized foreign exchange gain during the quarter due to revaluing the Indian-rupee based income tax receivable to U.S. dollars.

Deferred tax recovery for the quarter and year-to-date increased by $24 million and $25 million, respectively, due to a reduction in deferred tax liabilities resulting from a reduction in exploration and evaluation assets related to proceeds from a farm out and from a former partner in exchange for assuming the partner’s obligation for future drilling commitments.

In the prior year to date, the change in accounting estimate is related to deferred income tax as a result of estimating the amount of taxable temporary differences reversing during the tax holiday period.

Capital Expenditures, net of Proceeds of Farm-outs and Other Arrangements

The following table sets forth the capital additions and exploration and evaluation costs expensed directly to income, net of proceeds of farm-outs and other arrangements, for the six months ended September 30, 2012.

Six months ended September 30, 2012						
(thousands of U.S. dollars)	Additions to exploration and evaluation assets(1)(2)	Additions related to future drilling	Directly expensed exploration and evaluation costs(1)	Additions to property, plant and equipment(1)	Proceeds from farm outs and other arrangements	Total
Indonesia	46,490	27,799	18,428	129	(45,203)	47,643
Trinidad	26,482	1,516	15,122	404	-	43,524
All other	485	-	2,872	924	-	4,281
Total	73,457	29,315	36,422	1,457	(45,203)	95,448

(1) Share-based compensation and other non-cash items are excluded.
(2) Includes additions in the year that were subsequently written off.

Indonesia

Additions to exploration and evaluation assets for Indonesia for the six months ended September 30, 2012 relate to two wells in the Lhokseumawe block and one well in the North Ganal block. The first well in the Lhokseumawe block, with a cost of $12 million, did not reach target depth due to mechanical problems and was expensed in the first quarter of fiscal 2013. The second well in the Lhokseumawe block, with a cost of $12 million, and one well in North Ganal block, with a cost of $3 million, did not encounter commercial quantities of hydrocarbons and were expensed in the current quarter. The remaining additions in Indonesia relate to the costs of drilling inventory and activities to prepare for the upcoming drilling campaign. Subsequent to the end of the current quarter, drilling of the Jayarani-1 well in the Lhokseumawe block was completed and no commercial reservoir was encountered. Costs incurred to September 30, 2012 of $6 million along with costs incurred subsequent to end of the quarter related to this well will be expensed in the third quarter of fiscal 2013. Exploration and evaluation costs expensed directly to income include $13 million for seismic and other exploration projects and $5 million for branch office costs. In addition, the Company recorded proceeds of a farm-out of $9 million and received $36 million from a former partner in exchange for assuming the partner's obligation for future drilling commitments.

Trinidad and Tobago

Additions to exploration and evaluation assets for Trinidad and Tobago for the six months ended September 30, 2012 relate to the Shadow-1 and Maestro-1 wells drilled in Block 2AB. The Shadow-1 well with a cost of $20 million did not encounter significant hydrocarbon-bearing sandstone and was expensed in the current quarter. Subsequent to the end of the current quarter, hydrocarbons were encountered in the Maestro-1 well at the Lower Cretaceous level; however, no significant reservoir intervals that could be deemed commercial were encountered and costs incurred to September 30, 2012 of $5 million along with costs incurred subsequent to end of the quarter will be expensed in the third quarter of fiscal 2013. Exploration and evaluation costs expensed directly to income include $5 million of costs related to seismic exploration for the Guayaguayare area and $1 million of payments that are specified in the various PSCs.

BACKGROUND ON PROPERTIES

The Company's diversified portfolio of producing, development and exploration assets is described below.

Producing Assets

The Company's principal producing natural gas and crude oil assets are in the D6 Block in India and in Block 9 in Bangladesh.

D6 Block, India

The Company entered into the PSC for the D6 Block in India in 2000 and has a 10 percent working interest, with Reliance, the operator, holding a 60 percent interest and BP holding the remaining 30 percent interest. The D6 Block is 7,645 square kilometers lying approximately 20 kilometers offshore of the east coast of India.

Successful exploration programs in the D6 Block led to the discoveries of the Dhirubhai 1 and 3 natural gas fields in 2002 and the MA crude oil and natural gas field in 2006.

Production from the crude oil discovery in the MA field commenced in September 2008 and commercial production commenced in May 2009. Six wells are tied into a FPSO, which stores the crude oil until it is sold on the spot market at a price based on the Bonny Light reference price and adjusted for quality, and four of these wells are currently on production. The Company expects to drill an additional gas development well and convert the two suspended oil wells into gas producing wells to accelerate the production of the reservoir's gas reserves.

Field development of the Dhirubhai 1 and 3 fields included the drilling and tie-in of 18 wells, construction of an offshore platform and onshore gas plant facilities. Production from the Dhirubhai 1 and 3 natural gas discoveries commenced in April 2009 and commercial production commenced in May 2009. The natural gas produced from offshore is being received at an onshore facility at Gadimoga and is sold at the inlet to the East-West Pipeline owned by Reliance Gas Transportation Infrastructure Limited.

Production from the Dhirubhai 1 and 3 fields peaked in March 2010 and has decreased since then, primarily due to natural declines of the fields and greater than anticipated water production. Four additional wells have been drilled in the post-production phase of drilling. Based on the information obtained from three wells drilled within the main channel fairway, the Company has determined that it is not economic to tie-in any of these three wells at the present time. The fourth well was drilled outside of the main channel fairway and did not encounter economic quantities of natural gas. Six of the original 18 wells are currently shut-in and several others are choked, primarily due to current constraints in water handling capacity. Increased water handling capacity and additional booster compression is expected to be installed over the next two years to address the decline in reservoir pressure.

The Company expects production to continue to decline until new field production is added from identified development opportunities. See "Background on Properties – Development Opportunities".

The PSC for the D6 Block requires that natural gas be sold at arm's length prices, with "arm's length" defined as sales made freely in the open market between willing and unrelated sellers and buyers, and that the pricing formula be approved by the GOI. In May 2007, Reliance, on behalf of the joint venture partners, discovered an arm's length price for the sale of gas on a transparent basis with a term of three years and, accordingly, proposed a gas price formula to the GOI. In September 2007, the GOI approved a pricing formula with some modification to the proposed formula. As a result of these modifications, the gas price is capped at $4.20/MMBtu and the formula was declared effective for a period of five years rather than the three years proposed by Reliance. The Company has signed numerous gas sales contracts with customers in the fertilizer, power, steel, city gas distribution, liquefied petroleum gas market and pipeline transportation industries, and all of these contracts expire on March 31, 2014. In June 2012, Reliance submitted to the GOI for approval a proposal for a new crude oil-linked pricing formula to be used in new sales contracts for the period commencing April 1, 2014. The proposed formula was based on the pricing formula under a contract for long-term import of LNG into India and was universally accepted by arm's length buyers who bid in large numbers in an open price discovery process. Using JCC crude oil pricing for July 2012, the proposed pricing formula would result in a gas price that is approximately $13/MMBtu, three times the current gas price. The GOI is currently reviewing the proposed price formula.

The production and operating expenses for the D6 Block relate primarily to the offshore wells and facilities, the onshore gas plant facilities and the operating fee portion of the lease of the FPSO. The majority of these expenses are fixed in nature with repairs and maintenance expenditures incurred as required.

The Company calculates and remits profit petroleum expense to the GOI in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital, operating and other expenditures made by Reliance on behalf of the joint venture partners. Because there are unrecovered costs to date, the GOI's share of profit petroleum has amounted to the minimum level of one percent of gross revenue. Profit petroleum expense will increase above the minimum level once past unrecovered costs have been fully recovered. The Company has included certain costs in the profit petroleum calculations that are being contested by the GOI and has received notice from the GOI making allegations in relation to the fulfillment of certain obligations under the PSC for the D6 Block. Refer to note 14 to the consolidated financial statements for six months ended September 30, 2012 for a complete discussion of this contingency.

The Company currently pays royalty expense of five percent of gross revenue, increasing to ten percent of gross revenue in May 2016. Royalty payments are deductible in calculating profit petroleum.

The Company pays the greater of minimum alternate tax and regular income taxes for the D6 Block. In the calculation of regular income taxes, the Company believes it is entitled to a seven-year income tax holiday commencing from the first year of commercial production and has claimed the tax holiday in the filing of tax return for fiscal 2012. There is currently uncertainty in India regarding the applicability of this tax holiday to natural gas. Minimum alternate tax is the amount of tax payable in respect of accounting profits. Minimum alternate tax paid can be carried forward for 10 years and deducted against regular income taxes in future years.

Block 9, Bangladesh

In September 2003 the Company acquired a 60 percent working interest in the PSC for Block 9. Tullow, the operator, holds a 30 percent interest and the remaining 10 percent interest is held by BAPEX. Block 9 covers approximately 1,770 square kilometers of land in the central area of Bangladesh surrounding the capital city of Dhaka. Natural gas and condensate production for the Bangora field in Block 9 commenced in May 2006 and gas is transported from four currently producing wells to a gas plant in the block.

The Company's share of production from the Bangora field reached a sustained rate of production of 60 MMcf/d in 2009. The Company expects to drill two probable undeveloped locations in Fiscal 2014 which, if successful could offset the natural decline expected in the Bangora field through 2015. The Company has signed a GPSA including a price of $2.34/MMBtu (or $2.32/Mcf), which expires at the earliest of the end of commercial production, at expiry of the PSC (March 31, 2026) and 25 years after approval of the field development plan (May 15, 2032). Petrobangla is the sole purchaser of the natural gas production from this field. The sales delivery point is at facility and thereafter is the responsibility of Petrobangla and is transported via Trunk Pipeline.

The production and operating expenses for Block 9 relate primarily to the onshore wells and facilities, including a gas plant and pipeline. The majority of these expenses are fixed in nature with repair and maintenance expenditures incurred as required.

The Company calculates and remits profit petroleum expense to the GOB in accordance with the PSC for Block 9. The profit petroleum calculation considers capital, operating and other expenditures made by the joint venture, which reduces the profit petroleum expense. To date, the GOB's share of profit petroleum amounted to the minimum level of 34 percent of gross revenue based on the profit petroleum provisions of the PSC. The profit petroleum percentage of gross revenue will increase above the minimum level of 34 percent of gross revenue once past unrecovered allowable costs have been fully recovered.

Under the terms of the Block 9 PSC the Company does not make payment to the GOB with respect to income tax.

Development Opportunities

The Company has undeveloped discoveries in D6 and NEC 25 blocks in India and in Block 5(c) in Trinidad and Tobago. For each of the proposed developments of these discoveries, the Company shall make final investment decisions if and when development plans are approved by the respective governments with pricing terms for the natural gas sales acceptable to the respective joint venture partners. The Company expects that approval of any or all of these developments will significantly increase the Company's booked reserves and provide the opportunity for significant production growth in the next three to six years.

The following is a brief description of these opportunities and proposed development plans.

Additional Areas, D6 Block, India

The Company's exploration program has identified three additional areas in the D6 Block for potential future development. An integrated development strategy for the D6 Block, including these undeveloped areas, is currently being prepared by Reliance with input from the joint venture partners and under this strategy, the Company expects development plan for the three areas to be submitted for approval in late 2012 or early 2013. The development of these areas is expected to be completed within three to four years after the approval of the development plans. The plans are likely to include the re-entry and completion of certain existing wells and the drilling of new wells, all connected with new flow-lines and other facilities into existing D6 Block infrastructure,.

NEC-25 Block, India

The Company has a 10 percent working interest in the NEC-25 Block, with Reliance, the operator, holding a 60 percent interest and BP holding the remaining 30 percent interest. The remaining contract area comprises 9,461 square kilometres offshore adjacent to the east coast of India. Exploration and appraisal drilling has been conducted on the block and Reliance is working to finalize the development plan for seven discovered natural gas fields to be submitted for approval in early 2013. Based on work done to date, the development is expected to include the re-entry and completion of certain existing wells and the drilling of new wells, all connected via new flow-lines and other facilities into a new offshore central processing platform. The produced natural gas is expected to be transported onshore via a new pipeline.

Block 5(c), Trinidad and Tobago

The Company has a 25 percent working interest in Block 5(c) with the BG Group, the operator, holding the remaining 75 percent working interest in this offshore development area that covers 324 square kilometres. In October 2011, the BG Group submitted a development plan to the GTT for approval. Development of natural gas production from two discovered fields in the block is expected to require the drilling of new wells, construction of new flow-lines and other facilities, and expansion of an existing platform in the adjacent Block 6(b) operated by the BG Group.

Exploration Opportunities

The Company's business strategy is to commit resources to finding, developing and producing exploration opportunities that have the potential for a "high impact"' on the Company. Exploration acreage is generally obtained by committing to acquire and process a specified amount of seismic and in most cases, drill one or more exploration wells. The Company generally uses advanced technology including high resolution multi-beam data collection and analysis, sub-sea coring and focused 3D seismic to reduce costs associated with selecting prospects to drill and increase the probability of success. The Company generally uses the information acquired to farm-out its blocks to world-class industry partners under terms where the partners fund their share of sunk costs and carry a disproportionate share of drilling costs.

The Company holds interests in contract areas covering 176,071 gross square kilometers of undeveloped land, primarily in Indonesia and Trinidad and Tobago.

Indonesia

The Company holds interests in 22 offshore exploration blocks in Indonesia, covering 119,145 square kilometers. The Company has successfully farmed out interests in several of its blocks and is working with various parties on additional farm-outs to reduce its share of future drilling costs. The table below indicates the operator, the location of, the award date, working interest and the size of the block.

Block Name	Operator	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Lhokseumawe (1)	Zaratex	Aceh	Oct. 2005	30%	4,431
Bone Bay	Niko	Sulawesi S	Nov. 2008	100%	4,969
South East Ganal	Niko	Makassar Strait	Nov. 2008	100%	4,868
Seram	Niko	Seram NE	Nov. 2008	55%	4,991
South Matindok	Niko	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri	Niko	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Exxon	Papua NW	May 2009	45%	4,991
Kofiau	Niko	Papua W	May 2009	57.5%	5,000
Kumawa	Niko	Papua SW	May 2009	100%	5,004
East Bula	Niko	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau	Niko	Papua W	Nov. 2009	51% (2)	4,926
North Makassar	Niko	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV	Niko	Papua SW	Nov. 2009	51% (2)	6,389
Cendrawasih Bay II	Repsol	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III	Niko	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV	Niko	Papua NW	May 2010	50%	3,904
Sunda Strait I	Niko	Sunda Strait	May 2010	100%	6,960
Obi	Niko	Papua W	Nov. 2011	51% (3)	8,057
North Ganal	Eni	Makassar Strait	Nov. 2011	31%	2,432
Halmahera II	Statoil	Papua W	Dec. 2011	20%	8,215
South East Seram	Niko	Papua SW	Dec. 2011	100%	8,217
Aru	Niko	Papua SW	July 2012	60%	8,054

(1) In October 2012, the Company received government approval for its farm-in to the Lhokseumawe block.

(2) The Company has entered into farm-out agreements for the West Papua IV and Halmahera-Kofiau blocks that, subject to government approval, will be reduce its working interest to 48 percent and 40 percent, respectively.

(3) The Company has entered into a farm-out agreement for the Obi block that, subject to government approval, will reduce its working interest to 42 percent.

All of the Indonesian blocks are in their initial three year exploration period with the exception of the Lhokseumawe block. The seismic work commitments on the majority of the blocks have been fulfilled and as at September 30, 2012, the Company had remaining minimum work commitments to drill a total of ten wells. As at September 30, 2012, the Company's share of the remaining minimum work commitments as specified in the PSCs for the exploration period was $118 million to be spent at various dates through June 2015. The minimum work commitments are based on the Company's share of the estimated cost included in the PSCs and represent the amounts the host government may claim if the Company does not perform the work commitments. The actual cost of fulfilling work commitments is expected to materially exceed the amount estimated in the PSCs. The Company has applied or have plans to apply for extensions where drilling activity is planned. The Company is required to relinquish a portion of the exploration acreage after the first exploration period; however, the Company has received extensions in order to fulfill the well commitments on certain blocks.

Trinidad and Tobago

The Company holds interests in ten contract areas in Trinidad and Tobago, covering 9,945 square kilometers. The table below indicates the operator, the location of, the award date, the working interest and the size of the block.

Exploration Area	Operator	Location	Award Date	Working interest	Area (Square Kilometres)
Block 2AB	Niko	Offshore	July 2009	35.75%	1,605
Guayaguayare—Shallow Horizon	Niko	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare—Deep Horizon	Niko	Onshore/Offshore	July 2009	80%	1,190
Central Range—Shallow Horizon	Parex	Onshore	Sept. 2008	32.50%	734
Central Range—Deep Horizon	Parex	Onshore	Sept. 2008	40%	856
Block 4(b)	Niko	Offshore	April 2011	100%	754
NCMA2	Niko	Offshore	April 2011	56%	1,020
NCMA3	Niko	Offshore	April 2011	80%	2,107
Block 5(c)	BG Group	Offshore	July 2005	25%	324
MG Block (License)	Niko	Offshore	July 2007	70%	223

The seismic work commitments on the majority of the blocks have been fulfilled and as at September 30, 2012, the Company had remaining minimum work commitments to drill a total of eleven wells. As at September 30, 2012, the minimum remaining work commitments under the PSCs were $175 million, to be spent at various dates through April 2016. The actual cost of fulfilling work commitments may materially exceed the amount estimated in the PSCs. The Company is working with various parties on farm-outs to reduce its share of future drilling costs.

Other Properties

India

Hazira Field

Niko is the operator of the Hazira Field and holds a 33.33 percent interest in this field. The field is located close to several large industries about 25 kilometers southwest of the city of Surat and covers an area of approximately 50 square kilometers on and offshore. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area. The Company has constructed an offshore platform, an LBDP, a gas plant and an oil facility at the Hazira Field. The Company has one significant contract for the sale of natural gas from the Hazira Field at a price of $4.86/Mcf expiring April 30, 2016, which accounted for five percent of total revenues during the quarter. The commitment for future physical deliveries of natural gas under this contract exceeds the expected related future production from total proved reserves from the Hazira Field estimated using forecast prices and costs. Refer to note 14(c) to the consolidated financial statements for six months ended September 30, 2012 for a complete discussion of these contingencies.

Surat Block

The Company holds and is the operator of a development area in the 24 square kilometer Surat Block located onshore adjacent to the Hazira Field in Gujarat State, India. The natural gas production from the Surat Block commenced in April 2004 and is transferred to the customer via 6-inch pipeline to the customer's facility. The Company has a gas plant at Surat Block and all the production from the Surat Block is sold to one customer with a current price of $6.00/Mcf expiring March 31, 2013. Sales of natural gas to this customer accounted for two percent of the Company's total revenues during the quarter.

Madagascar

In October 2008, the Company farmed in on a PSC for a property located off the west coast of Madagascar covering an area of approximately 16,845 square kilometers. The Company will earn a 75 percent participating interest in the Madagascar block and any extension or renewal thereof or amendment thereto and are the operator of this block. The Company has completed a multi-beam sea bed coring and 3,200 square kilometers of 3D seismic on the block. The Company has work commitments for an exploration well and its share of the remaining costs pursuant to the PSC is $10 million prior to September 2015. The actual cost of fulfilling work commitments may exceed the amount estimated in the PSC.

Pakistan

The Company holds and operates the four blocks comprising the Pakistan Blocks, which are located in the Arabian Sea near the city of Karachi and cover an area of 9,921 square kilometers. The Company has acquired 2,142 square kilometers of 3D seismic data on the blocks. The Company has received a one-year extension to the Phase I exploration period through seismic exploration activity.

Kurdistan

The Company holds a 49% working interest and operates the Qara Dagh Block, which covers approximately 846 square kilometers onshore. The Qara Dagh Block has an initial exploration period of five years, extendable on a yearly basis up to a maximum period of seven contract years. A 2D seismic exploration program was conducted and data acquired on the block that led to the selection of a drilling location. An exploratory well was drilled between May 2010 and October 2011. The 2D seismic program and the initial exploratory well satisfy the work commitments for the first sub-period of the initial term of the PSC. The second sub-period of the initial term includes further 2D or 3D seismic data and drilling one exploration well. The Company's share of the estimated cost of the remaining work commitment for the exploration period is $6 million to be spent by May 2013.

SEGMENT PROFIT

India

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Natural gas revenue	40,007	63,545	85,120	130,358
Oil and condensate revenue [(1)]	12,125	18,884	22,457	37,653
Royalties	(2,601)	(4,136)	(5,456)	(8,541)
Profit petroleum	(1,016)	(1,314)	(8,338)	(3,237)
Production and operating expenses	(7,318)	(7,887)	(13,404)	(15,340)
Depletion and depreciation expense	(35,163)	(24,539)	(73,465)	(51,777)
Exploration and evaluation expenses	(414)	(85)	(354)	(542)
Current income tax recovery / (expense)	(281)	(1,180)	2,099	(4,293)
Minimum alternate tax expense	(3,125)	(4,917)	(4,410)	(12,798)
Deferred income tax reduction	8,409	4,603	3,912	(184)
Change in accounting estimate - deferred taxes	-	-	-	(57,865)
Segment profit / (loss)[(2)]	10,623	42,974	8,161	13,434
Daily natural gas sales (Mcf/d)	105,474	167,698	112,926	173,450
Daily oil and condensate sales (bbls/d) [(1)]	1,289	1,889	1,219	1,854
Operating costs ($/Mcfe)	$0.68	$0.48	$0.61	$0.43
Depletion rate ($/Mcfe)	$3.33	$1.47	$3.30	$1.53

(1) Production that is in inventory has not been included in the revenue or cost amounts indicated.
(2) Segment profit / (loss) is a non-IFRS measure as calculated above.

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

Revenue and Royalties

The Company's natural gas production for the quarter and year-to-date was 105 MMcf/d and 113 MMcf/d, respectively, compared to 168 MMcf/d and 173 MMcf/d respectively in the prior year's periods. The reduction in production was primarily due to natural declines and greater than anticipated water production at the D6 Block. Declines are expected to continue unless production volumes are added from new fields in the D6 Block.

Crude oil production decreased due to a reduction in reservoir pressure associated with production from the MA field in the D6

Block. The realized prices were $102/bbl and $100/bbl in the quarter and year-to-date, respectively, compared to $109/bbl and $111/bbl in the prior year's periods. Decreased production and sales price contributed to the decrease in crude oil and condensate revenue.

The decrease in royalties is a result of the decreased revenues described above. Royalties applicable to production from the D6 Block are five percent for the first seven years of commercial production and gas royalties applicable to the Hazira Field and Surat Block 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. An additional $6 million of profit petroleum expense for the Hazira Field was recognized and reduced crude oil and natural gas revenue in the period. The adjustment, related to crude oil and natural gas revenues earned in prior years, was the result of a court ruling finding that the 36-inch natural gas pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery.

For the D6 Block, the Company is able to use up to 90 percent of revenue to recover costs. The Government of India was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum expense will continue at this level until the Company has recovered its costs.

The Government of India was entitled to 25 percent and 20 percent of the profits from the Hazira Field and the Surat Block, respectively.

Production and Operating Expenses

Operating costs at the D6 Block decreased as less maintenance was conducted during the periods compared to the prior year's periods.

Depletion Expense

The depletion rate increased by $1.77/Mcfe on a year to date basis as a result of the revision to the reserve volumes and future costs included in the March 31, 2012 reserve report. The effect of the increased depletion rate on the depletion expense was partially offset by decreased production.

Income Taxes

There was a current income tax recovery as a result of the adjustment to profit petroleum described above, which is deductible for tax purposes.

Minimum alternate tax expense is calculated on accounting income from the D6 Block. Higher depletion rates reduced accounting income and minimum alternate tax expense.

Contingencies

The Company has contingencies related to natural gas sales contracts and the profit petroleum calculation for the Hazira Field and related to income taxes for the Hazira Field and the Surat Block as at September 30, 2012. Refer to note 14(c) to the consolidated financial statements for six months ended September 30, 2012 for a complete discussion of these contingencies.

Bangladesh

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	2011	Six months ended Sept. 30 2012	2011
Natural gas revenue	12,436	12,705	25,142	24,322
Condensate revenue	1,856	2,004	3,785	3,964
Profit petroleum	(4,836)	(4,979)	(9,792)	(9,577)
Production and operating expenses	(2,641)	(1,625)	(4,649)	(3,721)
Depletion and depreciation expense	(3,715)	(3,064)	(7,509)	(5,922)
Exploration and evaluation expenses	-	(133)	(180)	(392)
Segment profit / (loss)(1)	3,100	4,908	6,797	8,674
Daily natural gas sales (Mcf/d)	58,341	60,129	59,295	57,712
Daily condensate sales (bbls/d)	187	191	189	186
Operating costs ($/Mcfe)	$0.43	$0.25	$0.39	$0.35
Depletion rate ($/Mcfe)	$0.68	$0.54	$0.68	$0.54

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

Revenue, Profit Petroleum, Depletion and Operating Expenses

The natural gas price was consistent during the periods at $2.32/Mcf.

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 increased due to increased revenues from Block 9.

Production and operating expense increased due to the higher level of maintenance activity during the period.

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

Contingencies

The Company has contingencies related to various claims filed against it with respect to the Feni property in Bangladesh as at September 30, 2012. Refer to note 14 to the consolidated financial statements for the six months ended September 30, 2012 for a complete discussion of these contingencies.

Indonesia, Kurdistan and Trinidad and Tobago

(thousands of U.S. dollars)	Exploration and evaluation expense		Asset impairment		Income tax recovery		Depreciation and other		Segment Profit	
	Six months ended September 30,									
	2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
Indonesia	(48,426)	(27,431)	-	-	21,058	-	207	(56)	(27,161)	(27,487)
Kurdistan	(2,185)	(1,599)	(38,919)	-	-	-	-	(12)	(41,104)	(1,611)
Trinidad	(36,052)	(26,314)	-	-	-	-	(47)	(40)	(36,099)	(26,354)

Indonesia

Costs of $24 million related to the unsuccessful Candralila-1 and Ratnadewi-1 wells in the Lhokseumawe block and $3 million related to unsuccessful Lebah-1 well in the North Ganal block were expensed in the period, costs totaling $10 million relating to seismic and other exploration projects totaling were incurred for various blocks, $3 million was spent on new ventures and $5 million was incurred to operate the branch office. The prior year expense relates primarily to seismic exploration programs.

Kurdistan

The Company recognized an asset impairment of $39 million when it reassessed the recoverable amount of the Qara Dagh Block exploration and evaluation asset.

Trinidad and Tobago

Costs of $20 million related to the unsuccessful Shadow-1 well in Block 2AB were expensed in the period. Exploration and evaluation costs expensed directly to income include $7 million of seismic costs and $6 million payments that are specified in the various PSCs.

Corporate

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Share-based compensation	3,342	20,424	6,902	26,620
Finance expense	8,853	8,004	17,176	15,741
Foreign exchange loss / (gain)	(3,824)	7,181	968	7,243
Loss on short-term investments	32	9,783	276	8,568

Share-based compensation

The fair value per stock option granted decreased in the periods due to decreased stock price in the period.

Finance expense

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Interest expense	6,007	5,346	12,269	10,873
Accretion expense	2,162	1,951	4,158	3,741
Other	684	707	749	1,127
Finance expense	8,853	8,004	17,176	15,741

Interest expense increased as a result of the outstanding loan balance incurred in connection with the credit agreement with no corresponding borrowings attributable to a credit facility in the prior year's quarter. Accretion expense is on 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.

Foreign Exchange

	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Realized foreign exchange (gain) / loss	2,826	3,217	2,482	3,368
Unrealized foreign exchange loss / (gain)	(6,650)	3,964	(1,514)	3,875
Total foreign exchange loss / (gain)	(3,824)	7,181	968	7,243

The realized foreign exchange losses and gains arise primarily because of the difference between the Indian rupee and 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 gain in the year arose primarily on the revaluing of the Indian-rupee denominated income tax receivable and site restoration deposit to U.S. dollars and the strengthening of the Indian-rupee versus the U.S. dollar.

There were additional foreign exchange gains in the period 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 loss on short-term investments for the year was a result of marking the short-term investments to market value.

Netbacks

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

	Three months ended Sept 30, 2012			Three months ended Sept 30, 2011		
($/Mcfe)	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	5.01	2.61	4.19	5.00	2.61	4.39
Royalties	(0.25)	-	(0.16)	(0.25)	-	(0.19)
Profit petroleum	(0.10)	(0.88)	(0.37)	(0.08)	(0.88)	(0.28)
Production and operating expense	(0.68)	(0.43)	(0.61)	(0.48)	(0.25)	(0.43)
Operating netback	3.98	1.30	3.05	4.19	1.48	3.49
G&A			(0.14)			(0.08)
Other Income			0.02			-
Net finance expense			(0.56)			(0.37)
Current income tax expense			(0.02)			(0.05)
Minimum alternate tax			(0.20)			(0.22)
Funds from operations netback			2.15			2.77
Production and operating expenses			(0.02)			-
Exploration and evaluation costs			(3.33)			(2.04)
Other expense			(0.20)			(0.92)
Loss on short-term investment			-			(0.44)
Deferred income tax reduction			1.79			0.21
Net finance gain / (expense)			0.28			(0.29)
Depletion and depreciation expense			(2.47)			(1.25)
Earnings netback			(1.80)			(1.96)

Netbacks for India, Bangladesh and in total are calculated by dividing the revenue and costs for each country and in total by the total sales volume for each country and in total measured in Mcfe.

	Six months ended Sept 30, 2012			Six months ended Sept 30, 2011		
($/Mcfe)	India	Bangladesh	Total	India	Bangladesh	Total
Oil and natural gas revenue	4.89	2.62	4.13	4.97	2.63	4.41
Royalties	(0.25)	-	(0.16)	(0.25)	-	(0.19)
Profit petroleum	(0.38)	(0.89)	(0.55)	(0.10)	(0.89)	(0.29)
Production and operating expense	(0.61)	(0.39)	(0.53)	(0.43)	(0.35)	(0.41)
Operating netback	3.65	1.34	2.89	4.19	1.39	3.52
G&A			(0.13)			(0.09)
Other Income			0.01			-
Net finance expense			(0.44)			(0.32)
Current income tax reduction / (expense)			0.06			(0.10)
Minimum alternate tax			(0.13)			(0.29)
Funds from operations netback			2.26			2.72
Production and operating expenses			(0.02)			-
Exploration and evaluation costs			(2.70)			(1.33)
Other Expense			(1.39)			(0.60)
Loss on short-term investment			(0.01)			(0.19)
Deferred income tax reduction			0.75			-
Change in accounting estimate – deferred taxes			-			(1.30)
Net finance expense			(0.08)			(0.20)
Depletion and depreciation expense			(2.47)			(1.32)
Earnings netback			(3.66)			(2.22)

Netbacks for India, Bangladesh and in total are calculated by dividing the revenue and costs for each country and in total by the total sales volume for each country and in total measured in Mcfe.

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 the Company. 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 operations or 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

The Company's financial instruments consist of short-term investments, accounts receivable, long-term accounts receivable, accounts payable and accrued liabilities, borrowings and convertible debentures.

The Company is exposed to fluctuations in the value of 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 it operate. The Company manages the risk by converting cash held in foreign currencies to U.S. dollars as required to fund forecasted expenditures. The Company is exposed to changes in foreign exchange rates as the future interest and principal amounts 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 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 partially mitigates this risk. The Company does so in the normal course of business by entering into contracts with fixed natural 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 changes in the Brent crude price as the average Brent crude price from the preceding year (to a defined maximum) is a variable in the natural gas price for the current year, calculated annually, for the D6 Block natural 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.

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 determined 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 and $10 million for the three and six months ended September 30, 2012 were recorded for interest expense and accretion of the discount on the convertible debentures.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2012, the Company had unrestricted cash of $98 million and a working capital deficit (current assets less current liabilities) of $283 million. The deficit includes $314 million related to convertible debentures that mature on December 30, 2012.

On December 30, 2009, the Company entered into Cdn$310 million of convertible debentures. The debentures bear interest at a rate of five percent and mature on December 30, 2012. Interest is 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 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 may elect to convert all or a portion of the debentures at maturity into common shares at a six percent discount to the weighted average trading price for the 20 trading days prior to the maturity date. The Company continues to pursue its options for the repayment of the convertible debentures and expects resolution well in advance of maturity. The Company is working with the primary holder of the debentures regarding the amount and timing of a prepayment at par plus accrued interest, utilizing cash on hand and advances under its credit facility.

In January 2012, the Company entered into a three-year facility agreement for a $225 million revolving credit facility and a $25 million operating facility for general corporate purposes. The maximum available credit under this agreement is subject to review based on, among other things, updates to the Company's reserves. On September 18, 2012, the Company received notice from the syndicate of lenders of the redetermination of the borrowing base of the facility which resulted in a reduction of the Company's credit availability under the facility to an aggregate of $100 million. The Company has borrowed $41 million against this facility as of September 30, 2012.

In September 2012, Niko's board of directors decided to suspend the Company's quarterly dividend in connection with the commencement of the Company's significant exploration drilling program. The timing and level of future dividends, if any, will be reviewed periodically by the board of directors.

The Company's guidance on its capital program for the year ended March 31, 2013, net of proceeds of negotiated farm-outs and other arrangements, has been revised from $210 million to $170 million, due primarily to deferrals of development spending. In addition, Niko has funded and will continue to fund certain drilling inventory and other costs related to its drilling program in future years. Total spending for the year is expected to be approximately $205 million.

The Company is currently in negotiations with various third parties regarding farm-outs and other arrangements that have the potential to provide additional proceeds of $135 million during the year ended March 31, 2013 and is in preliminary discussions with additional third parties regarding the farm-out or sale of further assets.

The Company has a number of contingencies as at September 30, 2012 that could significantly impact liquidity. Refer to note 14 to the consolidated financial statements for the six months ended September 30, 2012 for a complete discussion of these contingencies.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information, in thousands of U.S. dollars unless otherwise indicated, for the eight most recently completed quarters to September 30, 2012:

Three months ended	Dec. 31, 2011	Mar. 31, 2012	June. 30, 2012	Sept. 30, 2012
Oil and natural gas revenue [(1)]	74,789	71,434	55,099	58,080
Net income (loss)	(40,405)	(183,324)	(92,121)	(28,573)
Per share				
Basic ($)	(0.78)	(3.55)	(1.78)	(0.55)
Diluted ($)	(0.78)	(3.55)	(1.78)	(0.55)

Three months ended	Dec. 31, 2010	Mar. 31, 2011	June. 30, 2011	Sept. 30, 2011
Oil and natural gas revenue [(1)]	99,220	94,168	88,277	86,810
Net income (loss)	25,806	6,234	(54,983)	(43,916)
Per share				
Basic ($)	0.50	0.12	(1.07)	(0.85)
Diluted ($)	0.50	0.12	(1.07)	(0.85)

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

Net income in the quarters was affected by:

- D6 gas production declined over the quarters due to well performance.
- 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.
- The Company expensed a portion of the exploration and evaluation costs during the quarters and the level of activity varies over the periods.
- The Company impaired assets of $133 million and long term receivables of $23 million in the quarter ended March 31, 2012 and assets of $39 million in the quarter ended June 30, 2012.
- 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 quarter ended March 31, 2011 and again in the quarter ended March 31, 2012 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.
- There was a deferred income tax recovery in the quarter ended March 31, 2012 related to the revision to the reserve estimate, which increased the value of the tax holiday for the D6 Block and there were deferred income tax recoveries related to spending in Indonesia and Trinidad applied against the deferred income tax liabilities recorded upon the acquisitions of Voyager Energy Ltd. and Black Gold Energy LLC.
- An additional $6 million of profit petroleum expense for the Hazira Field reduced oil and natural gas revenue in the year-to-date. The adjustment to profit petroleum expense was the result of a court ruling finding that the 36-inch natural gas sales pipeline that Niko and GSPC constructed to connect the Hazira Field to the local industrial area was not eligible for cost recovery.
- Deferred tax recovery for the quarter increased by $22 million, due to a reduction in deferred tax liabilities resulting from a reduction in exploration and evaluation assets related to proceeds from a farm out and from a former partner in exchange for assuming the partner's obligation for future drilling commitments.

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, 2012, available at www.sedar.com.

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 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 are 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 IASB 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 issued amendments to IAS 1 *Presentation of Financial Statements* requiring companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income (OCI) that may be reclassified to the profit or loss section of the income statement. The amendments apply to annual periods beginning on or after July 1, 2012.

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 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 required to be disclosed in quarterly 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 Company's Chief Executive Officer and Chief Financial Officer are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of internal controls over financial reporting. The Company's 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 IFRS.

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 September 30, 2012. 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 material adverse impact:

- 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 September 30, 2012. 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 November 13, 2012, the Company had the following outstanding shares:

	Number	Cdn$ Amount [(1)]
Common shares	51,641,845	1,325,403,000
Preferred shares	Nil	Nil
Stock options	3,847,003	-

(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 November 13, 2012 is $1,171,439,000.

ABBREVIATIONS

Bcfe	billion cubic feet equivalent
Bbl	barrel
CEO	Chief Executive Officer
CICA	Canadian Institute of Chartered Accountants
FPSO	floating production, storage and off-loading vessel
GPSA	gas purchase and sale agreement
GSPC	Gujarat State Petroleum Corporation Ltd.
GOB	Government of Bangladesh
GOI	Government of India
GRI	Government of the Republic of Indonesia
GTT	Government of Trinidad and Tobago
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MD&A	management's discussion and analysis
MMBtu	million British thermal units
MMcfe	million cubic feet equivalent
MMcf	million cubic feet
PSC	production sharing contract
/d	per day

All amounts are in thousands of U.S. dollars unless otherwise stated.
All thousand cubic feet equivalent (Mcfe) figures are based on the ratio of 1bbl:6Mcf.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (thousands of U.S. dollars)	As at Sept 30, 2012	As at Mar 31, 2012
Assets		
Current assets		
Cash and cash equivalents	98,060	64,495
Restricted cash	3,337	6,790
Accounts receivable (note 3)	71,389	61,247
Short-term investment	475	748
Inventories	11,155	9,961
	184,416	143,241
Restricted cash	14,329	11,283
Long-term accounts receivable	1,360	2,202
Long-term investment	2,796	2,752
Exploration and evaluation assets (notes 4, 13)	818,417	856,880
Property, plant and equipment (note 5, 13)	438,191	509,091
Income tax receivable (note 14e)	27,552	34,724
Deferred tax asset	62,226	58,314
	1,549,287	1,618,487
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	148,004	101,660
Current tax payable	1,301	1,220
Finance lease obligation	4,804	4,804
Convertible debentures(note 6)	313,661	306,052
	467,770	413,736
Decommissioning obligation	41,203	40,017
Finance lease obligation	41,038	43,671
Borrowings	41,000	25,000
Deferred tax liabilities	174,455	195,515
	765,466	717,939
Shareholders' Equity		
Share capital (note 7)	1,171,439	1,171,439
Contributed surplus	116,433	104,964
Equity component of convertible debentures	14,765	14,765
Currency translation reserve	(6,577)	(2,094)
Deficit	(512,239)	(388,526)
	783,821	900,548
	1,549,287	1,618,487

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars, except per share amounts)	2012	2011	2012	2011
Oil and natural gas revenue (note 8)	58,080	86,810	113,179	175,088
Production and operating expenses	(10,026)	(9,550)	(18,211)	(19,105)
Depletion and depreciation expense (note 5)	(39,204)	(27,778)	(81,616)	(58,969)
Exploration and evaluation expenses (note 9)	(52,879)	(45,117)	(89,300)	(59,270)
Loss on short-term investments	(32)	(9,783)	(276)	(8,568)
Asset (impairment) / recovery (note 4)	181	-	(38,919)	-
Other income (expenses)	311	-	311	78
Share-based compensation expense (note 7)	(3,342)	(20,424)	(6,902)	(26,620)
General and administrative expenses (note 10)	(2,266)	(1,857)	(4,323)	(4,015)
	(49,177)	(27,699)	(126,057)	(1,381)
Finance income	610	465	853	602
Finance expense (note 11)	(8,853)	(8,004)	(17,176)	(15,741)
Foreign exchange gain (loss)	3,824	(7,181)	(968)	(7,243)
Net finance expense	(4,419)	(14,720)	(17,291)	(22,382)
Loss before income tax	(53,596)	(42,419)	(143,348)	(23,763)
Current income tax reduction / (expense)	(285)	(1,183)	2,091	(4,290)
Minimum alternate tax expense	(3,125)	(4,917)	(4,410)	(12,797)
Deferred income tax reduction / (expense)	28,433	4,603	24,971	(58,049)
Income tax (expense)	25,023	(1,497)	22,652	(75,136)
Net loss	(28,573)	(43,916)	(120,696)	(98,899)
Foreign currency translation gain / (loss)	(9,635)	15,549	(4,483)	14,432
Comprehensive loss for the period	(38,208)	(28,367)	(125,179)	(84,467)
Loss per share: (note 12)				
Basic	$ (0.55)	$ (0.85)	$ (2.34)	$ (1.92)
Diluted	$ (0.55)	$ (0.85)	$ (2.34)	$ (1.92)

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(unaudited) (thousands of U.S. dollars, except number of common shares)	Common shares (#)	Share capital	Contributed surplus	Currency translation reserve	Equity component of convertible debentures	Deficit	Total
Balance, March 31, 2011	51,526,901	1,162,319	63,037	(8,344)	14,765	(53,392)	1,178,385
Options exercised	74,070	6,408	(1,556)	-	-	-	4,852
Share-based compensation expense	-	-	31,337	-	-	-	31,337
Net loss for the period	-	-	-	-	-	(98,899)	(98,899)
Payment of dividends(1)	-	-	-	-	-	(6,391)	(6,391)
Foreign currency translation	-	-	-	14,432	-	-	14,432
Balance, September 30, 2011	51,600,971	1,168,727	92,818	6,088	14,765	(158,682)	1,123,716
Options exercised	40,874	2,712	(732)	-	-	-	1,980
Share-based compensation expense	-	-	12,878	-	-	-	12,878
Net loss for the period	-	-	-	-	-	(223,729)	(223,729)
Payment of dividends(1)	-	-	-	-	-	(6,115)	(6,115)
Foreign currency translation	-	-	-	(8,182)	-	-	(8,182)
Balance, March 31, 2012	51,641,845	1,171,439	104,964	(2,094)	14,765	(388,526)	900,548
Options exercised	-	-	-	-	-	-	-
Share-based compensation (note 7)	-	-	11,469	-	-	-	11,469
Net loss for the period	-	-	-	-	-	(120,696)	(120,696)
Payment of dividends(1)	-	-	-	-	-	(3,017)	(3,017)
Foreign currency translation	-	-	-	(4,483)	-	-	(4,483)
Balance, September 30, 2012	51,641,845	1,171,439	116,433	(6,577)	14,765	(512,239)	783,821

(1) The Company paid dividends of $0.12 per share in the six months ended September 30, 2011 and $0.06 per share in the six months ended September 30, 2012.

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

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASHFLOWS

(unaudited)	Three months ended Sept 30,		Six months ended Sept 30,	
(thousands of U.S. dollars)	2012	2011	2012	2011
Cash flows from operating activities:				
Net loss	(28,573)	(43,916)	(120,696)	(98,899)
Adjustments for:				
Depletion and depreciation expense	39,204	27,776	81,616	58,969
Accretion expense	2,162	1,951	4,158	3,741
Deferred income tax (reduction) / expense	(28,433)	(4,603)	(24,972)	58,049
Unrealized foreign exchange loss / (gain)	(6,650)	3,964	(1,514)	3,875
Loss on short-term investment	32	9,783	276	8,568
Asset impairment	(181)	(69)	38,919	(69)
Exploration and evaluation write-off	37,015	43,191	49,482	56,046
Share-based compensation expense	5,533	19,688	10,935	27,637
Change in non-cash working capital	(1,333)	(3,557)	4,307	13,184
Change in long-term accounts receivable	10,401	(2,249)	8,619	25,141
Net cash from operating activities	29,177	51,959	51,130	156,242
Cash flows from investing activities:				
Exploration and evaluation expenditures	(60,155)	(59,526)	(93,053)	(175,109)
Property, plant and equipment expenditures	(7,866)	(5,794)	(11,060)	(8,804)
Proceeds from other arrangements (note 4)	36,000	-	36,000	-
Farm-out proceeds (note 4)	9,203	-	9,203	-
Restricted cash contributions	(900)	(2,000)	(3,102)	(2,600)
Release of restricted cash	1,300	-	3,319	4,459
Disposition of investments	-	-	-	1,106
Change in non-cash working capital	43,028	11,250	30,813	4,283
Net cash used in investing activities	20,610	(56,070)	(27,880)	(176,665)
Cash flows from financing activities:				
Proceeds from issuance of share capital, net of issuance costs	-	4,743	-	4,852
Change in loans and borrowings	-	-	16,000	-
Reduction in finance lease liability	(1,350)	(1,206)	(2,633)	(2,347)
Dividends paid	-	(3,166)	(3,017)	(6,391)
Net cash from financing activities	(1,350)	371	10,350	(3,886)
Change in cash and cash equivalents	48,437	(3,740)	33,600	(24,309)
Effect of translation on foreign currency cash	36	(2,021)	(35)	(608)
Cash and cash equivalents, beginning of period	49,587	89,186	64,495	108,342
Cash and cash equivalents, end of period	98,060	83,425	98,060	83,425

The accompanying notes are an integral part of these 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 13. The Company's common shares are traded on the Toronto Stock Exchange.

2. Basis of Presentation

The condensed interim consolidated financial statements include the accounts of Niko Resources Ltd. (the "Company") and all of its subsidiaries. The majority of the exploration, development and production activities of the Company are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities. The condensed interim consolidated financial statements have been prepared in accordance with IAS 34 – Interim Financial Reporting using accounting policies consistent with International Financial Reporting Standards ("IFRS").

The interim consolidated financial statements have been prepared following the same accounting policies and methods of application as the audited consolidated financial statements for the fiscal year ended March 31, 2012. The disclosures provided herein are incremental to those included with the annual consolidated financial statements and the notes thereto for the year ended March 31, 2012. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto for the year ended March 31, 2012.

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

These financial statements were authorized for issue by the Board of Directors on November 13, 2012.

3. Accounts receivable

(thousands of U.S. dollars)	As at Sept 30, 2012	As at March 31, 2012
Oil and gas revenues receivable	22,190	28,033
Receivable from joint venture partners	23,022	13,004
Advances to vendors	3,593	1,751
Prepaid expenses and deposits	5,302	4,816
VAT receivable	12,444	9,405
Other receivables	4,838	4,238
	71,389	61,247

4. Exploration and evaluation assets

(thousands of U.S. dollars)	Six months ended Sept 30, 2012	Year ended March 31, 2012
Opening balance	856,880	762,221
Additions (note 13)	93,705	164,976
Transfers	-	5,354
Expensed	(49,592)	(71,500)
Impairment	(38,384)	-
Disposals and other arrangements	(45,203)	(2,355)
Foreign currency translation	1,011	(1,816)
Closing balance	818,417	856,880

The Company expensed $50 million of exploration costs related to three unsuccessful exploration wells in Indonesia and one unsuccessful exploration well in Trinidad. The Company also estimated the recoverable amount of Kurdistan exploration and evaluation assets and recognized an impairment of $38 million. In addition, the Company recorded proceeds of a farm-out of $9 million and received $36 million from a former partner in exchange for assuming the partner's obligations for future drilling commitments.

5. Property, plant and equipment

a. *Development assets*

(thousands of U.S. dollars)	Six months ended Sept 30, 2012	Year ended March 31, 2012
Opening balance	16,988	18,421
Additions	2,971	7,447
Expensed	-	-
Transfers to other asset categories	-	(8,880)
Closing balance	19,959	16,988

b. *Producing assets*

(thousands of U.S. dollars)	Six months ended Sept 30 , 2012	Year ended March 31, 2012
Cost		
Opening balance	1,042,869	1,019,696
Additions	-	16,458
Transfers from other asset categories	-	6,791
Foreign currency translation	43	(76)
Closing balance	1,042,912	1,042,869
Accumulated depletion		
Opening balance	(453,957)	(312,767)
Additions	(80,051)	(141,266)
Foreign currency translation	(42)	76
Closing balance	(534,050)	(453,957)
Impairment	(133,415)	(133,415)
Net producing assets	375,447	455,497

c. *Other Property, plant and equipment*

(thousands of U.S. dollars)	Land and buildings	Transportation Vehicles	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2012	18,346	2,376	8,754	10,772	40,248
Additions / Transfers	3	-	383	3	389
Disposals	-	(27)	(136)	-	(163)
Foreign currency translation	-	-	58	-	58
Balance, Sept 30, 2012	18,349	2,349	9,059	10,775	40,532
Accumulated depreciation					
Balance, March 31, 2012	(6,127)	(1,482)	(4,449)	(7,341)	(19,399)
Additions	(508)	(87)	(723)	(247)	(1,565)
Disposals	-	-	-	-	-
Foreign currency translation	-	-	(43)	-	(43)
Balance, Sept 30, 2012	(6,635)	(1,569)	(5,215)	(7,588)	(21,007)
Net book value, Sept 30, 2012	11,714	780	3,844	3,187	19,525

(thousands of U.S. dollars)	Land and buildings	Transportation Vehicles	Office equipment, furniture and fittings	Pipelines	Total
Cost					
Balance, March 31, 2011	18,108	2,395	5,978	10,752	37,233
Additions	238	-	2,907	20	3,165
Disposals	-	(19)	(89)	-	(108)
Foreign currency translation loss	-	-	(42)	-	(42)
Balance, March 31, 2012	18,346	2,376	8,754	10,772	40,248
Accumulated depreciation					
Balance, March 31, 2011	(4,880)	(1,148)	(3,390)	(6,738)	(16,156)
Additions	(1,247)	(352)	(1,126)	(603)	(3,328)
Disposals	-	18	34	-	52
Foreign currency translation gain	-	-	33	-	33
Balance, March 31, 2012	(6,127)	(1,482)	(4,449)	(7,341)	(19,399)
Net book value, March 31, 2012	12,219	894	4,305	3,431	20,849

d. *Capital work-in-progress*

(thousands of U.S. dollars)	As at Sept 30, 2012	As at March 31, 2012
Capital work-in-progress	23,260	15,757

6. Convertible Debentures

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. The Company has the option to convert all or a portion 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 maturity date. The Company continues to pursue its options for the repayment of the convertible debentures and expects resolution well in advance of maturity. The Company is working with the primary holder of the debentures regarding the amount and timing of a prepayment at par plus accrued interest, utilizing cash on hand and advances under its credit facility.

7. 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 5,164,184 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. The stock options are settled in equity.

Stock option transactions for the respective periods were as follows:

	Six months ended Sept 30, 2012		Year ended March 31, 2012	
	Number of options	Weighted average exercise price (Cdn$)	Number of options	Weighted average exercise price (Cdn$)
Opening balance	3,978,003	75.62	4,243,897	85.37
Granted	247,625	26.16	1,160,750	55.70
Forfeited	(31,000)	70.73	(155,750)	86.43
Cancelled	-	-	(587,500)	102.13
Expired	(190,750)	90.52	(568,450)	80.97
Exercised	-	-	(114,944)	58.01
Closing balance	4,003,878	71.89	3,978,003	75.62
Exercisable	1,022,249	85.72	952,624	85.19

The following table summarizes stock options outstanding and exercisable under the plan at Sept 30, 2012:

	Outstanding Options			Exercisable Options	
Exercise Price	Options	Remaining life (years)	Weighted average exercise price (Cdn$)	Options	Weighted average exercise price (Cdn$)
13.48 - 19.99	115,500	4.44	13.92	-	-
20.00 - 29.99	-	-	-	-	-
30.00 - 39.99	110,500	3.74	36.22	-	-
40.00 - 49.99	1,214,066	1.97	47.62	154,811	49.35
50.00 - 59.99	252,375	3.37	52.04	-	-
60.00 - 69.99	204,375	2.74	63.24	41,000	63.55
70.00 - 79.99	66,750	2.33	73.41	6,750	76.87
80.00 - 89.99	593,563	1.19	86.41	314,563	89.07
90.00 - 99.99	1,056,750	1.34	95.86	458,000	95.64
100.00 - 109.99	365,249	2.45	104.36	42,750	106.63
110.00 – 112.64	24,750	2.11	111.09	4,375	111.30
	4,003,878	1.99	71.89	1,022,249	85.72

The weighted average share price during the six months ended September 30, 2012 was $21.17 (2011 - $66.13).

c. Fair value measure of equity instruments granted

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

	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six Months ended Sept.30, 2011
Grant-date fair value	Cdn$5.04	Cdn$20.18	Cdn$8.55	Cdn$24.85
Market price per share	Cdn$13.92	Cdn$57.05	Cdn$26.16	Cdn$74.39
Exercise price per option	Cdn$13.92	Cdn$57.05	Cdn$26.16	Cdn$74.39
Expected volatility	51%	42%	47%	41%
Expected life (years)	4.1	4.5	3.9	4.1
Expected dividend rate	1.7%	0.4%	1.1%	0.3%
Risk-free interest rate	1.2%	1.7%	1.3%	2.1%
Expected forfeiture rate	9.5%	6.0%	9.2%	6.0%

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 *d.* below for categorization of share-based payment expense during the period.

d. Share-based compensation disclosure

The Company prepares its statement of comprehensive income (loss) 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 (loss).

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Share-based compensation expense included in:				
Exploration and evaluation assets	268	122	534	475
Operating expense	330	493	637	1,017
Exploration and evaluation expense	1,861	1,996	3,397	3,225
Share-based compensation expense	3,342	20,424	6,902	26,620
Total	5,801	23,035	11,470	31,337

8. Revenue

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Natural gas sales	52,444	76,294	110,262	154,679
Oil and condensate sales	14,090	20,992	26,497	41,765
Less:				
Royalties	(2,602)	(4,183)	(5,450)	(8,542)
Government's share of profit petroleum	(5,852)	(6,293)	(18,130)	(12,814)
Oil and natural gas revenue	58,080	86,810	113,179	175,088

Revenues from oil and gas sales to Petrobangla comprised 21 percent of natural gas, oil and condensate sales for the six months ended September 30, 2012 (2011 - 14 percent).

In June 2012, the Company recorded a $6 million increase in profit petroleum expense due to a court ruling indicating the 36-inch pipeline is not eligible for cost recovery. The Company has appealed the decision with division bench of Delhi High Court.

9. Exploration and evaluation expenses

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Geological and geophysical	6,555	35,071	18,274	38,992
Exploration and evaluation (well cost)	37,448	564	49,592	579
General and administrative	3,835	4,005	8,672	7,726
Production sharing contract annual payments	1,797	3,191	6,492	7,433
New ventures	1,383	290	2,873	1,315
Share-based compensation	1,861	1,996	3,397	3,225
Exploration and evaluation	52,879	45,117	89,300	59,270

10. General and administrative expenses

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Salaries	927	953	2,054	1,191
Legal fees	84	819	187	2,855
Consultants	636	259	708	419
Rent	148	191	286	382
Management fees	122	164	264	327
Audit fees	172	138	212	251
Insurance	-	-	10	-
Others	536	104	1,023	(221)
Head office costs reclassified according to function	(359)	(771)	(421)	(1,189)
General and administrative expense	2,266	1,857	4,323	4,015

The Company prepares its statement of comprehensive income (loss) 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 / (loss). General and administrative expenses of $4 million and $9 for the three and six months ended September 30, 2012 (2011 - $4 million and $8 million) are categorized as exploration and evaluation expenses and of $3 million and $5 million for the three and six months ended September 30, 2012, (2011 - $3 million and $6 million) are categorized as production and operating expenses.

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Audit fees	201	162	243	325
Management fees	125	167	270	332
Legal fees	261	900	460	3,137
Salary	3,286	3,457	6,987	5,374
Insurance	1,573	1,562	3,332	3,156
Security	208	226	425	447
Rent	521	386	1,008	776
Travel	116	215	357	437
Consultants	890	313	1,063	526
Non-operating and other	1,995	487	4,664	1,216
Office costs	342	740	579	1,510
Total	9,518	8,615	19,388	17,236

11. Finance expense

(thousands of U.S. dollars)	Three months ended Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Interest expense related to capital lease	1,360	1,472	2,759	3,012
Interest expense on long-term debt	753	-	1,781	-
Interest expense on convertible debentures	3,894	3,874	7,729	7,861
Accretion expense on convertible debentures	1,459	1,358	2,765	2,624
Accretion expense on decommissioning obligations	703	593	1,393	1,117
Bank fees and charges and other finance costs	684	707	749	1,127
Finance expense	8,853	8,004	17,176	15,741

12. 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 Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Net loss	(28,573)	(43,916)	(120,696)	(98,899)

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 Sept 30, 2012	Three months ended Sept 30, 2011	Six months ended Sept 30, 2012	Six months ended Sept 30, 2011
Weighted average number of common shares used in the calculation of basic and diluted earnings per share	51,641,845	51,576,804	51,641,845	51,552,168

As a result of the net loss in the periods ended September 30, 2012 and 2011, the outstanding stock options of 4,003,878 and 3,766,752, respectively, and shares issuable upon conversion of the outstanding debentures of 2,805,430 as at September 30, 2012 and 2011 were considered anti-dilutive to the loss per share and were excluded from the weighted average number of common shares for the purposes of diluted earnings per share. The average market value of the Company's common shares for purposes of calculating the dilutive effect of stock options for the periods was based on quoted market prices for the periods that the options were outstanding. The number of shares issuable upon conversion of the outstanding debentures is based on the conversion price of Cdn$110.50 per common share, which is applicable to conversion at the option of the holder until 60 days prior to the maturity date.

13. 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. All of Bangladesh sales are received from one customer and this customer accounted for 21 percent of sales during the six months ended September 30, 2012.

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*

	Six months ended September 30, 2012		Year ended March 31, 2012	
	Additions to:			
Segment	Exploration and evaluation assets (E&E)	Property, plant and equipment (PP&E)	Exploration and evaluation assets	Property, plant and equipment
Bangladesh	-	955	63	3,004
India	111	292	2,432	18,599
Indonesia	66,737	8,214	16,676	-
Kurdistan	373	(565)[(1)]	24,795	-
Madagascar	2	-	9	-
Pakistan	-	-	248	-
Trinidad	26,482	1,913	120,753	1,466
All other	-	51	-	3,165
Total	93,705	10,860	164,976	26,234

(1) Negative additions in property, plant and equipment for Kurdistan are the result of impairment of inventory.

	As at September 30, 2012			As at March 31, 2012		
Segment	Total E&E	Total PP&E	Total assets	Total E&E	Total PP&E	Total assets
Bangladesh	4,737	26,579	40,995	4,737	31,605	46,617
India	136,214	396,609	669,644	136,104	454,421	730,134
Indonesia	503,791	10,221	555,871	510,161	-	534,923
Kurdistan	11,532	-	14,505	50,519	749	54,573
Madagascar	1,211	44	1,347	1,209	-	1,377
Pakistan	248	15	323	248	-	310
Trinidad	160,684	3,581	189,246	153,902	1,467	190,617
All other	-	1,142	77,356	-	20,849	59,936
Total	818,417	438,191	1,549,287	856,880	509,091	1,618,487

Three months ended Sept 30, 2012													
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other Income / (Loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	14,292	(4,836)	-	(2,641)	(3,715)	-	-	-	-	-	-	-	3,100
India	52,132	(1,016)	(2,601)	(7,318)	(35,163)	(414)	-	-	-	-	-	5,003	10,623
Indonesia	-	-	-	-	(56)	(25,089)	311	-	-	-	-	20,025	(4,809)
Kurdistan	-	-	-	-	5	(1,281)	-	-	181	-	-	-	(1,095)
Madagascar	-	-	-	-	(7)	(330)	-	-	-	-	-	-	(337)
Pakistan	-	-	-	-	(1)	(99)	-	-	-	-	-	-	(100)
Trinidad	-	-	-	-	(24)	(24,940)	-	-	-	-	-	-	(24,964)
Canada	109	-	-	(67)	(247)	(726)	-	-	-	-	-	(5)	(936)
All other	-	-	-	-	4	-	(32)	(3,342)	-	(2,266)	(4,419)	-	(10,055)
Total	66,533	(5,852)	(2,601)	(10,026)	(39,204)	(52,879)	279	(3,342)	181	(2,266)	(4,419)	25,023	(28,573)

Three months ended Sept 30, 2011													
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Gain / (Loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	14,709	(4,979)	-	(1,625)	(3,064)	(133)	-	-	-	-	-	-	4,908
India	82,429	(1,314)	(4,136)	(7,887)	(24,539)	(85)	-	-	-	-	-	(1,494)	42,974
Indonesia	-	-	-	-	(28)	(21,338)	-	-	-	-	-	-	(21,366)
Kurdistan	-	-	-	-	(6)	(681)	-	-	-	-	-	-	(687)
Madagascar	-	-	-	-	(7)	(273)	-	-	-	-	-	-	(280)
Pakistan	-	-	-	-	(1)	(589)	-	-	-	-	-	-	(590)
Trinidad	-	-	-	-	(20)	(20,914)	-	-	-	-	-	-	(20,934)
Canada	103	-	(2)	(38)	(113)	-	-	-	-	-	-	-	(50)
All other	-	-	-	-	-	(1,104)	(9,783)	(20,424)	-	(1,857)	(14,720)	(3)	(47,891)
Total	97,241	(6,293)	(4,138)	(9,550)	(27,778)	(45,117)	(9,783)	(20,424)	-	(1,857)	(14,720)	(1,497)	(43,916)

Six months ended Sept 30, 2012													
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other Income / (Loss) on short-term investments	Share-based compensation expense	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	28,927	(9,792)	-	(4,649)	(7,509)	(180)	-	-	-	-	-	-	6,797
India	107,577	(8,338)	(5,456)	(13,404)	(73,465)	(354)	-	-	-	-	-	1,601	8,161
Indonesia	-	-	-	-	(104)	(48,426)	311	-	-	-	-	21,058	(27,161)
Kurdistan	-	-	-	-	-	(2,185)	-	-	(38,919)	-	-	-	(41,104)
Madagascar	-	-	-	-	(14)	(701)	-	-	-	-	-	-	(715)
Pakistan	-	-	-	-	(3)	(191)	-	-	-	-	-	-	(194)
Trinidad	-	-	-	-	(47)	(36,052)	-	-	-	-	-	-	(36,099)
Canada	255	-	6	(158)	(474)	(1,210)	-	-	-	-	-	(7)	(1,588)
All other	-	-	-	-	-	(1)	(276)	(6,902)	-	(4,323)	(17,291)	-	(28,793)
Total	136,759	(18,130)	(5,450)	(18,211)	(81,616)	(89,300)	35	(6,902)	(38,919)	(4,323)	(17,291)	22,652	(120,696)

Six months ended Sept 30, 2011													
Segment	Natural gas, condensate and oil sales	Profit petroleum expense	Royalty expense	Production and operating expense	Depletion and depreciation expense	Exploration and evaluation expense	Other (expense) / (Loss) on short-term investments	Share-based compensation expenses	Asset impairment	General and administrative expense	Net finance expense	Income tax (reduction) / expense	Segment profit (loss)
Bangladesh	28,286	(9,577)	-	(3,721)	(5,922)	(392)	-	-	-	-	-	-	8,674
India	168,011	(3,237)	(8,541)	(15,340)	(52,741)	(542)	-	-	-	-	-	(75,140)	12,470
Indonesia	-	-	-	-	(56)	(27,431)	-	-	-	-	-	-	(27,487)
Kurdistan	-	-	-	-	(12)	(1,599)	-	-	-	-	-	-	(1,611)
Madagascar	-	-	-	-	(13)	(530)	-	-	-	-	-	-	(543)
Pakistan	-	-	-	-	(3)	(795)	-	-	-	-	-	-	(798)
Trinidad	-	-	-	-	(40)	(26,314)	-	-	-	-	-	-	(26,354)
Canada	147	-	(1)	(44)	(181)	-	-	-	-	-	-	-	(79)
All other	-	-	-	-	(1)	(1,667)	(8,490)	(26,620)	-	(4,015)	(22,382)	4	(63,171)
Total	196,444	(12,814)	(8,542)	(19,105)	(58,969)	(59,270)	(8,490)	(26,620)	-	(4,015)	(22,382)	(75,136)	(98,899)

14. 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 September 30, 2012).	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 422,026,000 ($5.17 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
- (ii) taka 828,579,000 ($10.15 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 ($10.36 million) for environmental damages, an amount subject to be increased upon further assessment;
- (iv) taka 6,330,398,000 ($77.53 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 14(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'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 estimates the cash amount to settle the contingency at US$11.6 million. The Company believes that the agreement with its 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 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 matter is subjudice in a court of law. The Company believes that the outcome is not determinable.

d. In a May 2012 letter, the GOI alleged that the joint venture partners in the D6 Block are in breach of the PSC for the D6 Block as they failed to drill all of the wells and attain production levels contemplated in the Addendum to the Initial Development Plan for the Dhirubhai 1 and 3 fields. The GOI has further asserted that joint venture costs totalling $1.462 billion (the Company's share totalling $146.2 million) are therefore disallowed for cost recovery. The joint venture partners are of the view that the disallowance of recovery of costs incurred by the joint venture has no basis in the terms of the PSC and that there are strong grounds to challenge the action of the GOI. Reliance has commenced arbitration proceedings against the GOI challenging the allegations and the disallowance of cost recovery. To the extent that any amount of joint venture costs are disallowed, such amount would be treated as profit petroleum in the future, a portion of which would be payable to the GOI under the PSC. Because profit petroleum percentages for the joint venture partners and the GOI change as the joint venture partners recover specified percentages of their investments, the potential impact on the Company's future profit petroleum expense (which represents the GOI's share of profit petroleum) is dependent on the future revenue and expenditures in the block and cannot be precisely determined at this time. Based on the economic inputs used for the proved and proved plus probable reserves in the March 31, 2012 Ryder Scott Report, the Corporation has estimated the potential undiscounted before tax impact to be between $25 to $46 million. The arbitral tribunal is in the process of being constituted with Reliance and the GOI having nominated two of the three arbitrators. The outcome of these proceedings is not determinable.

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 unfavorable tax assessments related to taxation years 1999 through 2008. 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 ("CITA"); the Income Tax Appellate tribunal ("ITAT"); the High Court; and the Supreme Court. For taxation years 1999 to 2004, the Company has received favorable rulings at ITAT and the revenue Department has appealed to the High Court. For the 2005 taxation year, the Company has received a favorable ruling at CITA. For the 2006, 2007 and 2008 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 2009 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 $34 million and write off of approximately $22 million of the net income tax receivable). In addition, the Company could be obligated to pay interest on taxes for the past periods.

f. The Cauvery and D4 Blocks in India are under relinquishment. The Company believes it has fulfilled all commitments for the Cauvery 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.

g. Various lawsuits have been filed against the Company for incidents arising in the ordinary course of business. In the opinion of management, the outcome of the lawsuits, now pending, is not determinable or not material to the Company's operations. Should any loss result from the resolution of these claims, such loss will be charged to operations in the year of resolution.