NIKO REPORTS RESULTS FOR THE YEAR ENDED MARCH 31, 2010

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 fiscal year ended March 31, 2010 (“fiscal 2010”). The operating results are effective June 23, 2010.

PRESIDENT'S REPORT TO THE SHAREHOLDERS

The entire Niko team is proud of our accomplishments during the past year.

Natural gas production from the D6 Block commenced in April 2009 and has continued uninterrupted since start-up. Current D6 gas production of 2.2 Bcf/d comes from the development of two discoveries within this 1.9 million acre block. Niko has a 10 percent interest in the D6 block. There have been 23 additional gas discoveries (including six discoveries since March 31, 2009) and Niko expects dramatic increases in reserves once development plans are prepared and approved.

The NEC-25 Block has nine natural gas discoveries in the northern part of the block and six discoveries in the southern AJ area. Five of the six discoveries within the AJ area were drilled since March 31, 2009. The joint venture has recently decided to drill three more wells in the AJ area. The Company expects NEC-25 to add significant reserves once development plans are prepared and approved.

The year also included a massive expansion of our exploration acreage. The most significant contribution to this expansion was the acquisition of Black Gold Energy LLC, which holds interests in several Indonesian blocks. The acreage obtained in the acquisition, when combined with previously held acreage and acreage additions since the acquisition, results in Niko being the largest non-government holder of deepwater exploration acreage in Indonesia. The acquisition also led to key Black Gold personnel joining the Niko team. They bring extensive knowledge and impressive technology to Niko.

Furthering the expansion, Niko completed an acquisition of a private company with interests in three areas in Trinidad and also acquired an additional 10 percent interest in the Qara Dagh block in Kurdistan.

To summarize the successes of the past year and future opportunities, Niko has:

- a solid production base;
- the potential to add significant reserves from the D6 and NEC-25 blocks; and
- the potential for high impact discoveries from multiple exploration blocks.

Finally, Niko has never been as financially strong as it is today. We reported earnings of $119 million, the largest in our history. We have a current cash balance of $246 million compared to $193 million of debt excluding convertible debentures. Further, we expect next year’s operating cash flow to be approximately $150 million greater than our capital expenditures.

We are excited about our future. In the current year we intend to conduct extensive seismic operations and expect exploration drilling in six blocks. We also expect to evaluate potential reserve/resource additions at D6 and NEC 25.

On behalf of the Board of Directors,

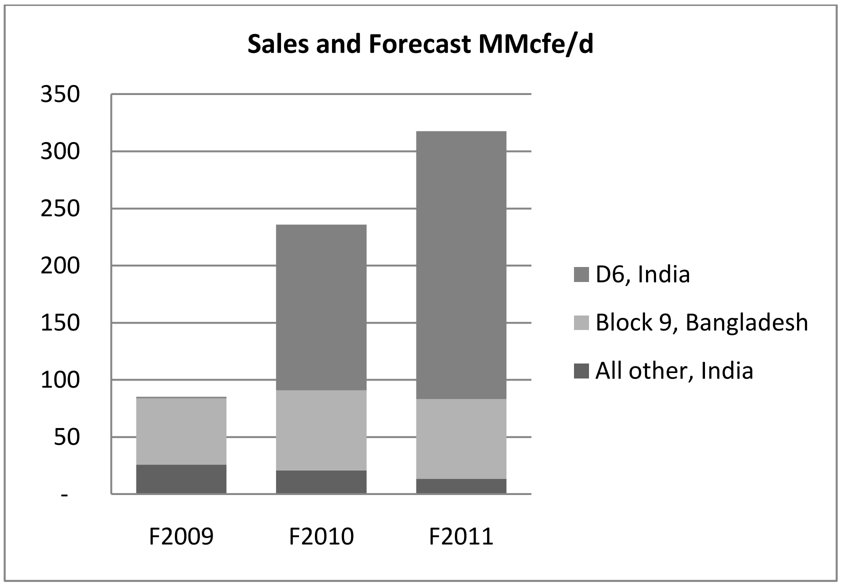
"Signed"

Edward S. Sampson
Chairman of the Board, President and CEO
June 23, 2010

OPERATIONS REVIEW

Sales Volumes

The Company's actual production for the years ended March 31, 2009 and 2010 and the forecast production for the year ending March 31, 2011 are displayed below. All amounts discussed in this section are the Company's share of sales.



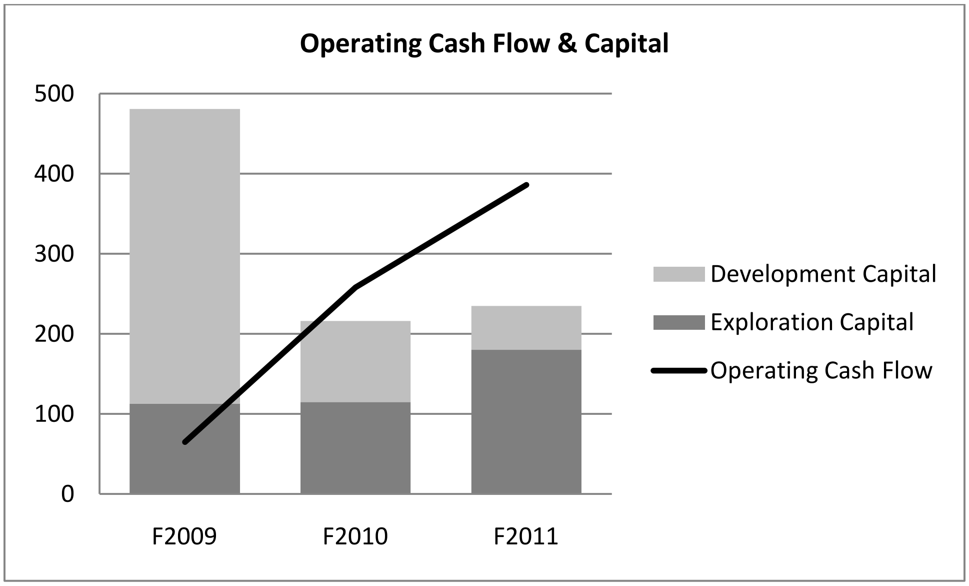
Gas production from the D6 Block commenced in April 2009 and average production for the year was 139 MMcf/d. The March 2010 exit rate of 217 MMcf/d has been used for the F2011 forecast. The forecast is expected to increase when additional gas sales contracts are signed.

D6 oil production has increased with two additional wells that have been put online resulting in average sales of 1,096 Bbls/d for the year with an exit production rate for March 2010 in excess of 2,000 Bbls/d. Production in fiscal 2011 will benefit from an entire year of production from the two wells that went on production in February 2010.

Facilities upgrades at Block 9 and the commencement of production from the Bangora-3 well have resulted in an increase of 24 percent in production from Block 9. Average production for the year was 68 MMcfe/d and the exit rate for March 2010 was 71 MMcfe/d. Production for fiscal 2011 is forecast to continue at this rate.

Production from the Hazira and Surat fields was 21 MMcfe/d. The forecast production reflects natural declines in these fields.

Operating Cashflow and Capital Expenditures



Fiscal 2009 was a year with significant spending to develop D6 reserves. Operating cash flows did not include D6 natural gas production. Overall capital spending exceeded operating cash flows by approximately $416 million.

In Fiscal 2010, the Company began to ramp-up its D6 production and operating cash flow increased dramatically to approximately US$258 million. The Company spent $115 million on exploration as more fully described below and spent a further $101 million, primarily on the D6 development. Operating cash flows exceeded capital spending by approximately $42 million.

For Fiscal 2011, exploration spending is expected to increase to approximately $180 million, the largest in Niko's history. In addition, further development activity in the D6 Block is expected to require approximately $55 million. Operating cash flow is expected to increase to $386 million and exceed capital spending by approximately $150 million.

The discussion below provides additional detail on i) operating cash flows and netbacks; ii) exploration acreage; and iii) capital expenditures.

i) Operating Cash flow and Netbacks

The following tables outline the Company's actual operating cash flow and operating netback (neither of which is a GAAP measure) for the years ended March 31, 2009 and 2010 and forecast operating cash flow and operating netback for the year ending March 31, 2011:

Years ending March 31,	2009 (US$000s)	2009 (US$/Mcfe)(1)	**2010 (US$000s)**	**2010 (US$/Mcfe)(1)**	2011 (US$000s)	2011 (US$/Mcfe)(1)
Oil and natural gas revenues	104,993	3.37	**334,111**	**3.88**	477,000	4.11
Royalties	(4,801)	(0.15)	**(14,979)**	**(0.17)**	(21,000)	(0.18)
Profit petroleum	(22,863)	(0.73)	**(29,533)**	**(0.34)**	(29,000)	(0.25)
Operating expense	(12,367)	(0.39)	**(31,125)**	**(0.36)**	(41,000)	(0.35)
Operating cash flow/netback	64,962	2.10	**258,474**	**3.01**	386,000	3.33

(1) Mcfe is derived by converting oil and condensate to natural gas in the ratio of 1 bbl:6 Mcf.

Operating Cash flow

The commencement of gas production from the D6 Block contributed to the 218 percent increase in the Company's total revenues for Fiscal 2010. The increase in royalties and operating expenses were primarily related to production from the D6 Block. Profit petroleum with respect to the D6 block was one percent of revenues, and will continue at this level until the Company has recovered its costs. The forecast revenues for Fiscal 2011 increases from additional D6 volumes. The profit petroleum for Fiscal 2011 is forecast to be lower than F2010 primarily due to Hazira where the F2011 expense will benefit from cost recovering increased capital spending.

Operating Netback

Average oil and natural gas revenue per Mcfe improves in each year shown above because D6 production receives a higher price than the Company's production from its other properties and from increasing oil production and market prices for oil.

ii) Exploration acreage

Niko has increased its exploration acreage by more than 136 percent since March 31, 2009. This was accomplished primarily through acquisitions described in our MD&A and partially through capital spending as discussed below. A comparison of Niko's net exploration land position as at March 31, 2009 and June 23, 2010 is shown below:

	(millions of acres)	
	March 31, 2009	**June 23, 2010**
India	1.3	**1.3**
Indonesia	2.2	**15.2**
Kurdistan	0.1	**0.1**
Madagascar	2.7	**2.7**
Pakistan	2.5	**2.5**
Trinidad	-	**0.5**
Bangladesh	1.1	**1.1**
	9.9	**23.4**

iii) Capital Expenditures and Forecast

(millions of U.S. dollars)(net to the Company)	**Actual spending For the year ended March 31, 2010**	Forecast spending For the year ending March 31, 2011
Exploration		
India	**50**	56
Indonesia	**39**	29
Kurdistan Region	**12**	16
Madagascar	**5**	28
Pakistan	**2**	1
Trinidad	**5**	37
New Ventures / Other	**2**	13
Development		
India	**91**	51
Bangladesh	**10**	4
Total	**216**	235

Exploration Expenditures (for the Year ended March 31, 2010)

- India

D6 Block exploration: There was drilling activity on seven exploration wells during the year. The rig was released from six of the wells during the year and was released from the seventh well, AW1, during April 2010. Six of the seven wells were successful: AR2, AS1 and AV1 were appraisal wells in the “R-complex”; AW1 was an appraisal of previous discoveries; and BA1 and BA2 were drilled in the deeper southern part of the block. The BA2 well encountered hydrocarbons, however, it was not drilled to the planned total depth due to complications while drilling. As a result, the joint venture is considering options to re-drill or twin the BA-2 well. The AR1 well, which is another “R-complex” appraisal well and the AK3 well, which is an oil prospect, are currently being drilled. Exploration drilling is expected to be ongoing on the D6 Block.

D4 Block: Processing of the seismic on the D4 Block has been completed and three preliminary drilling locations have been identified. Evaluation work is ongoing to finalize the drilling locations. Drilling is expected to commence in Fiscal 2011.

Cauvery: Two unsuccessful wells were drilled in Cauvery during the year and were abandoned.

NEC-25: During the year, the Company conducted an appraisal drilling campaign near the AJ1 discovery in the southern part of the block. The campaign included five wells being the AJ2, AJ3, AJ5, AJ6 and AJ7 wells and all five wells encountered gas bearing sands and confirmed significant hydrocarbon potential for NEC-25. A further three wells are planned in the AJ area and AJ9 is currently being drilled. See “Exploration Forecast” below for the projected timing of these wells.

While not drilled in the past year there have been nine discoveries in the northern part of the block.

- Indonesia

In mid-October 2009, the Company commenced a large scale 2D seismic program. The program used one vessel that traveled from block-to-block in order to minimize costs and downtime and maximize seismic coverage. By the end of March 2010, the program had accumulated over 14,000 kilometres covering seven blocks. In April 2010, the vessel moved to the eighth block and shot a further 1,000 kilometres of 2D seismic.

Acquisition of 3D seismic had accumulated to over 4,400 square kilometres by the end of March 2010 and an additional 900 square kilometres were acquired in April 2010.

In addition to the cost of these seismic programs, there was capital spending in the year for signature bonuses and other block-related expenditures.

- Kurdistan

During the year, 354 kilometres of 2D seismic was acquired in Kurdistan. Interpretation led to the selection of a drilling location on the crest of the very large Qara Dagh anticline. Drilling commenced in May 2010 and is expected to be completed by September 2010.

Capital expenditures in the year also include drilling preparation costs and the cost of various bonuses required as per the production sharing contract (PSC).

- Madagascar

A 10,000-square-kilometre multi-beam survey in Madagascar was completed in April 2010. Analysis of the data is nearing completion. A 3,000-square-kilometre 3D survey began in April 2010 and will be completed in July 2010. The 3D seismic will fulfill the Phase II work commitment. Drilling is expected to commence in the fourth quarter of Fiscal 2012.

Costs incurred during the year were for the acquisition and reprocessing of existing 2D seismic data, the multi-beam survey and carrying costs of the block.

- Pakistan

The Company began processing of the 2,000 square kilometres of 3D seismic acquired in Pakistan. The 3D seismic program is expected to identify stratigraphic potential, resolve structural complexity and indicate the presence of hydrocarbons. Drilling is expected to commence in the third quarter of Fiscal 2012.

- Trinidad

Capital spending in Trinidad during the year was for the bonuses required as per the PSC and carrying costs of Block 2AB. See "Exploration Forecast" for expected timing for seismic and drilling activities.

Development Expenditures (for the Year ended March 31, 2010)

- India

D6 Block: Development spending in the year included well completions and connecting wells to the offshore platform for the D6 gas development and drilling the MA6H and MA7H wells, well completions and connecting wells to the FPSO for the D6 oil development.

Hazira: One well of the three-well drilling program in the Hazira block was drilled during Fiscal 2010.

- Bangladesh

Bangladesh development spending in the year was for facilities upgrades, the workover of the Bangora-3 well, well testing and payment of the guarantee associated with the work commitment for the block.

Exploration Forecast (for the Year Ending March 31, 2011)

The Company expects to spend $180 million to complete the planned exploration program for the year ending March 31, 2011. The chart below shows the planned work program for Fiscal 2011 and the tentative work program for Fiscal 2012.

	Year ending March 31, 2011				Year ending March 31, 2012			
Location	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
India								
D6	Drilling Drilling	Drilling Drilling	Drilling Drilling	Drilling Drilling	Drilling Drilling	Drilling Drilling	Drilling Drilling	Drilling Drilling
D4				Drilling		Drilling		Drilling
NEC-25	Drilling	Drilling	Drilling	Drilling				
Pakistan							Drilling	
Madagascar	Seismic	Seismic						Drilling
Kurdistan	Drilling					Drilling		
Indonesia								
Bone Bay	Seismic			Drilling				
Cendrawasih		Seismic					Drilling	
Cendrawasih II				Seismic				
Cendrawasih III					Seismic			
Cendrawasih IV					Seismic			
East Bula			Seismic	Seismic				
Halmahera-Kofiau	Seismic	Seismic						
Kofiau	Seismic							Drilling
Kumawa						Drilling		
Seram			Seismic	Seismic			Drilling	
S. Matindok						Drilling		
S.E. Ganal					Drilling			
Sunda Strait					Seismic			
West Papua IV		Seismic						
West Sageri							Drilling	
Trinidad								
Block 2AB			Seismic			Drilling	Drilling	Drilling
Guayguayare				Seismic			Drilling	Drilling
Central Range		Drilling	Drilling		Seismic	Drilling		

Drilling planned by the Company
Seismic Work planned by the Company

Development Forecast (for the Year Ending March 31, 2011)

Forecast capital expenditures for the D6 Block include the re-entry into existing wells and drilling new wells in the D6 gas development, the cost of connecting them to the existing infrastructure and early procurement activities for compression.

At Hazira, multiple zones of interest have been identified on logs for the well that was drilled in Fiscal 2010. Niko is waiting for the arrival of a workover rig to test these zones. The first well drilled will be deepened to evaluate a deeper zone of interest that was not originally targeted. Forecast expenditures include the second well, which was drilled subsequent to March 31, 2010, and the third well, which is currently being drilled.

Forward-Looking Information and Material Assumptions

This report on results for the year ended March 31, 2010 contains forward-looking information including forward-looking information about Niko's operations, reserve estimates, production and capital spending.

Forward-looking information is generally signified by words such as "forecast", "projected", "expect", "anticipate", believe", "will", "should" and similar expressions. This forward-looking information is based on assumptions that the Company believes were reasonable at the time such information was prepared, but assurance cannot be given that these assumptions will prove to be correct, and the forward-looking information in this report on results for the year ended March 31, 2010 should not be unduly relied upon. The forward-looking information and the Company's assumptions are subject to uncertainties and risks and are based on a number of assumptions made by the Company, any of which may prove to be incorrect. Forward-looking information in this report on the results ended March 31, 2010 includes, but is not necessarily limited to, the following:

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

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

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

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

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis and updates reserve estimates on an annual basis. Refer to "Risk Factors" contained in the Company's management's discussion and analysis for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided in this report on results for the year ended March 31, 2010.

This Management's Discussion and Analysis (MD&A) of the financial condition, results of operations and cash flows of Niko Resources Ltd. ("Niko" or "the Company") for the year ended March 31, 2010 should be read in conjunction with the audited consolidated financial statements and accompanying notes for the year ended March 31, 2010. This MD&A is effective June 23, 2010. Additional information relating to the Company, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

Effective March 31, 2009, the Company adopted the U.S. dollar as its reporting currency. All financial information is presented in U.S. thousands of dollars unless otherwise indicated.

The fiscal year for the Company is the 12-month period ended March 31. The terms "Fiscal 2010", "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2009 through March 31, 2010. The terms "prior year" and "Fiscal 2009" are used throughout the MD&A for comparative purposes and refer to the period from April 1, 2008 through March 31, 2009. The term "Fiscal 2008" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2007 through March 31, 2008. The fourth quarter is the period from January 1, 2010 to March 31, 2010. The term "Fiscal 2012" is used throughout this MD&A and in all cases refers to the period from April 1, 2011 through March 31, 2012. The term "Fiscal 2011" is used throughout this MD&A and in all cases refers to the period from April 1, 2010 through March 31, 2011.

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

Less than 1 percent of total corporate volumes and total corporate revenue are from Canadian oil and Bangladeshi condensate. Therefore, the results from Canadian oil and Bangladeshi condensate production are not discussed separately.

Forward-Looking Information and Material Assumptions

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

Forward-looking information in this MD&A includes, but is not necessarily limited to, the following:
Forecast production rates: The Company prepares production forecasts taking into account historical and current production, actual and planned events that are expected to increase or decrease production and production levels indicated in the Company's reserve reports.

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

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

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

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

Non-GAAP Measures
The selected financial information presented throughout the MD&A is prepared in accordance with Canadian generally accepted accounting principles (GAAP), except for "funds from operations", "operating netback", "funds from operations netback", "earnings netback" and "segment profit", which are used by the Company to analyze the results of operations.

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

By examining operating netback, funds from operations netback, earnings netback and segment profit, the Company is able to evaluate past performance by segment and overall. Operating netback is calculated as oil and natural gas revenues less royalties, profit petroleum expenses and operating expenses for a given reporting period, per thousand cubic feet equivalent (Mcfe) of production for the same period, and represents the before-tax cash margin for every Mcfe sold.

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

Segment profit is defined as oil and natural gas revenues less royalties, profit petroleum expenses, operating expenses, depletion, depreciation and accretion expense and current and future income taxes related to each business segment.

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

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

OVERALL PERFORMANCE

Funds from Operations

Years ended March 31,	**2010**	2009
Oil and natural gas revenues	**334,111**	104,993
Royalties	**(14,979)**	(4,801)
Profit petroleum	**(29,533)**	(22,863)
Operating expense	**(31,125)**	(12,367)
Interest and other income	**12,679**	11,649
Interest and financing expense	**(19,843)**	(1,498)
General and administrative expense	**(11,069)**	(7,125)
Realized foreign exchange gain	**(1,582)**	3,320
Current income tax expense	**(24,851)**	(5,059)
Funds from operations(1)	**213,808**	66,249

(1) Funds from operations is a non-GAAP measure as calculated above.

Natural gas production from the Dhirubhai 1 and 3 gas fields in the D6 Block commenced in April 2009, comprising the majority of the increase in revenues in the year. The remaining increase is attributable to oil sales from the D6 Block, which commenced in November 2008, and an increase in Bangladesh revenue as a result of facility upgrades at Block 9 and the Bangora-3 well going on-stream. These increases more than offset natural declines at Hazira and Surat.

Royalties, operating expense and current income tax expense increased with the increased production described above.

Profit petroleum increased with increased production from Block 9 and because the Company shared profits from Surat with the Government of India during the year. Profit petroleum payable to the Government of India with respect to the D6 Block was $2.3 million or one percent of revenues.

Interest and other income in the year includes a $9.1 million adjustment related to a 36-inch pipeline that is connected to the Hazira facilities. Due to a dispute that was in arbitration, the Company had been assuming that it could not include the costs of the 36-inch pipeline for cost recovery, specifically, as a deduction in the calculation of profit petroleum. During the year, the Company was successful in arbitration and, as a result, pipeline costs will be eligible for cost recovery and the Company recognized the adjustment in the year. Interest and other income also includes $2.7 million on an income tax refund.

ALL AMOUNTS ARE IN THOUSANDS OF U.S DOLLARS UNLESS OTHERWISE INDICATED 14

The interest and financing expense relates to the lease of the Floating Production, Storage and Offloading vessel (FPSO) for D6 oil production that commenced in November 2008, interest expense on the long-term debt that was expensed subsequent to commencement of D6 gas production in April 2009 and interest expense on the convertible debentures, which were issued on December 30, 2009.

The net increase in general and administrative expense was a result of higher use of outside services, increased bonus and increased number of employees.

The Company's realized foreign exchange arises on the settlement of Indian-rupee denominated working capital.

Net Income

Years ended March 31,	**2010**	2009
Funds from operations (non-GAAP measure)	**213,808**	66,249
Unrealized foreign exchange (loss) gain	**(8,572)**	4,784
Gain (loss) on short-term investments	**14,554**	(24,380)
Equity gain (loss) on long-term investment	**(91)**	(982)
Impairment of long-term investment	**-**	(4,186)
Gain on risk management contracts	**-**	494
Discount of long-term account receivable	**(176)**	(265)
Stock-based compensation expense	**(19,778)**	(15,294)
Asset impairment	**-**	(1,258)
Depletion, depreciation and accretion	**(101,367)**	(44,029)
Future income tax reduction	**20,410**	-
Net income (loss)	**118,788**	(18,867)

Net income increased substantially in the year compared to the prior year. The increase is primarily a result of the increase in funds from operations as described above. Other factors affecting net income are explained below.

The unrealized foreign exchange loss arises primarily 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.

While there were no additional purchases during the year, there was a gain on marking the short-term investments to market value.

The increase in stock-based compensation expense in the year is primarily a result of the increased fair value expense per stock option and an increase in the number of stock options being expensed.

Depletion expense increased primarily due to the increased production with the commencement of gas production from the D6 Block.

The future income tax reduction is the result of a tax credit available for future years related to minimum alternative tax paid for the D6 Block in the current year.

ALL AMOUNTS ARE IN THOUSANDS OF U.S DOLLARS UNLESS OTHERWISE INDICATED 15

BACKGROUND ON PROPERTIES

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

India

Cauvery – The Company has a 100 percent working interest and operates the block, which covers 957 square kilometres. The Company has performed the seismic work and drilled four of the five wells required under the first exploration phase. The estimate cost of the remaining work commitment is $2.0 million. The Company has received an extension to the exploration period to March 2011 in order to evaluate the technical merit of the block.

D4 – The Company has a 15 percent interest in the D4 Block, located in the Mahanadi Basin offshore from the east coast of India. The block, which is currently in the exploration phase, encompasses more than 17,000 square kilometres. The commitment for Phase I exploration includes seismic work and drilling three exploration wells. Originally, the work commitment was to be completed by September 2009; however, the Government of India is in the process of approving a blanket extension of up to three years for this and other deepwater blocks, prompted by the shortage of deepwater drilling rigs. The Indian government has historically granted extensions, when required; however, there is a risk that the extension will not be granted. The seismic work has been completed and drilling is planned to commence in the first calendar quarter of 2011. The Company's share of the estimated cost of the remaining work commitment is $10 million.

D6 – The Company has a 10 percent working interest in the 7,645-square-kilometre D6 Block. The scope of work under Phase I of the development for the Dhirubhai 1 and 3 natural gas discoveries has been completed. The development of the MA oil discovery is ongoing. Production from the MA discovery began in September 2008 and from the Dhirubhai 1 and 3 discoveries in April 2009. The Company has been granted petroleum mining licences for the discoveries expiring in 2028 and 2025, respectively. Oil production is sold on the spot market at a price based on Bonny Light and adjusted for quality. Gas production is sold under long-term gas contracts using a pricing formula approved by the Government of India, which currently results in a price of $4.20/MMBtu net and there is a marketing margin of $0.135/MMBtu earned in addition to the price formula. This equates to a sales price of approximately $3.95/Mcf. There have been several gas discoveries since Dhirubhai 1 and 3. A development plan for nine such discoveries was submitted to the Government of India in July 2008, however, based on the Government's advice, in December 2009 the plan was modified to include four rather than nine discoveries. This does not mean other discoveries will not be developed. Rather, additional development plans can be expected in the future.

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

In addition, the Company pays a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company pays 10 percent of profits when the IM is less than 1.5; 16 percent between 1.5 and 2; 28 percent between 2 and 2.5; and 85 percent thereafter. As at March 31, 2010, the profit share was 10 percent.

Hazira – The Company has a 33 percent working interest in the 50-square-kilometre Hazira onshore and offshore block on the west coast of India, which lies adjacent to a large industrial corridor about 25 kilometres southwest of the city of Surat. The Company has a petroleum mining licence that expires in September 2014, which can be extended. The Company has two contracts for the sale of gas production from the field expiring in March 2013 and April 2016 at current prices up to US$4.86/Mcf and sells any production in excess of contracted amounts to one of the contracted customers at a price of US$4.86/Mcf. In addition to the price indicated, the Company collects the 10 percent royalty, that is payable to the government, from the customer. The Company pays a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company does not have profits to share when the IM is less than one; shares 10 percent of profits between one and 1.5; 20 percent between 1.5 and 2; 25 percent between 2 and 2.5; 35 percent between 2.5 and 3; and 40 percent thereafter. As at March 31, 2010, the profit share was 25 percent.

NEC-25 – The Company has a 10 percent working interest in the NEC-25 Block, which covers 9,461 square kilometres in the Mahanadi Basin off the east coast of India. The Company has fulfilled its capital commitments for the block, is currently drilling a well and plans to drill three additional appraisal wells. Once appraisal drilling is concluded, the Company expected to submit a development plan to the Government of India.

Surat – The Company holds a development area of 24 square kilometres containing the Bheema and NSA shallow natural gas fields. These fields have been producing natural gas since April 2004. The Company has a petroleum mining licence that expires in September 2024. The Company has one contract for the sale of gas production at a price of $6.00/Mcf until March 31, 2011. The contract is expected to be renewed at the end of Fiscal 2011. In addition to the price indicated, the Company collects the 10 percent royalty, payable to the government, from the customer. In addition, the Company will pay a percentage of the profits from the block to the government, which varies with the Investment Multiple (IM). The Company shares 20 percent of profits when the IM is between one and 1.5; 30 percent between 1.5 and 2; 40 percent between 2 and 2.5; 50 percent between 2.5 and 3; and 60 percent thereafter. As at March 31, 2010, the profit share was 20 percent.

Bangladesh

Block 9 – The Company holds a 60 percent interest in this 6,880-square-kilometre onshore block that encompasses the capital city of Dhaka. Natural gas and condensate production from this field began in May 2006. As per the PSC, the Company has rights to produce for a period of 25 years and this arrangement is extendable if production continues beyond this period. The Company sells gas under a gas purchase and sales agreement (GPSA) at a current price of $2.34/MMBtu (approximately $2.33/Mcf) for a period up to 25 years. The Company shares a percentage of the profits from the block with the government, which varies with production and whether or not the Company has recovered its investment. The Company pays to the government 61 percent and 66 percent of profits, respectively, before and after costs are recovered on natural gas production up to 150 MMcf/d. Profits on natural gas are calculated as the minimum of (i) 55 percent of revenue for the period and (ii) revenue less operating and capital costs incurred to date. As at March 31, 2010, the profit share was 61 percent.

Feni and Chattak – The Feni field covers 43 square kilometres and is located 6 kilometres west of the main natural gas line to Chittagong. The Chattak structure covers 376 square kilometres and rights to this block were obtained in October 2003. The Company produced natural gas from the Feni field from November 2004 to April 2010. As per the joint venture agreement (JVA), the Company has rights to produce until October 2023 and this arrangement can be extended if production continues beyond this period. The Company was selling gas under a GPSA including a price of $1.75 per Mcf, which expired in November 2009 and can be extended with mutual consent. The Company has proposed postponing extension of the GPSA pending resolution of the various claims raised against the Company as described in note 25 to the consolidated financial statements for the year ended March 31, 2010. Payment for the gas is being delayed as a result of the claims. On April 30, 2010, the Company suspended production from the Feni field claiming that Petrobangla's failure to pay for the natural gas already delivered has created a force majeure event under the JVA. See further discussion in note 25 to the consolidated financial statements for the year ended March 31, 2010.

Indonesia

The Company holds interests in PSCs for 16 offshore exploration blocks covering 79,739 square kilometres. The chart below indicates the location, award date, the Company's working interest and the size of the block.

Block Name	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Bone Bay	Sulewasi SW	Nov. 2008	45%	4,969
South East Ganal(1)	Makassar Strait	Nov. 2008	100%	4,868
Seram(1)	Seram North	Nov. 2008	100%	4,991
South Matindok(1)	Sulewasi NE	Nov. 2008	100%	5,182
West Sageri(1)	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Papua NW	May 2009	45%	4,991
Kofiau(1)	West Papua	May 2009	100%	5,000
Kumawa	Papua SW	May 2009	45%	5,004
East Bula(1)	Seram NE	Nov. 2009	100%	6,029
Halmahera-Kofiau(1)	Papua W	Nov. 2009	80%	4,926
North Makassar	Makassar Strait	Nov. 2009	50%	1,787
West Papua IV(1)	Papua SW	Nov. 2009	80%	6,389
Cendrawasih II	Papua NW	May 2010	50%	5,073
Cendrawasih III(1)	Papua NW	May 2010	50%	4,689
Cendrawasih IV(1)	Papua NW	May 2010	50%	3,904
Sunda Strait I(1)	Sunda Strait	May 2010	100%	6,960

(1) Operated by the Company.

All of the blocks are in the first exploration period, which is a three-year period. All of the blocks have a seismic commitment and most of the blocks have a single well commitment. The Company's share of the remaining work commitments during the first exploration period is estimated at $135 million.

Kurdistan Region

The Company has a 37 percent interest and carries the proportionate cost for the regional government's interest, resulting in a 46 percent cost interest in the onshore Qara Dagh block. The block covers approximately 846 square kilometres, in the Sulaymaniyah Governorate of the Federal Region of Kurdistan in Iraq. The exploration period is for a term of five years and is extendable by two one-year terms.

The first exploration phase is for three years expiring in May 2011 and the Company has commitments under this phase for seismic and drilling one exploratory well. Processing and interpretation of the seismic program is complete. The Company began drilling the exploratory well in May 2010. The Company's share of the estimated remaining costs under the first exploration phase is $12 million.

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Trinidad

The Company holds interests in five PSCs for three exploration areas covering 3,652 square kilometres. The Company has a 35.75 percent interest in Block 2AB; a 32.5 percent and 40 percent interest in the Shallow and Deep Horizon Central Range PSCs, respectively; and a 65 percent and 80 percent interest in the Shallow and Deep Horizon Guayaguayare PSCs, respectively.

Block 2AB covers 1,605 square kilometres offshore Trinidad and the Company has minimum work commitments to acquire and process 864 square kilometres of 3D seismic and drill three exploration wells by July 2012.

The Central Range block covers an onshore area of 856 square kilometres spanning from the west to east coasts of Trinidad. The Company has remaining minimum work commitments to acquire 168 kilometres of 3D seismic and drill three wells by September 2012.

The Guayaguayare block covers a 1,190 square-kilometre onshore and offshore area located on the southeast coast of Trinidad. The Company has minimum work commitments to acquire 130 square kilometres of 3D seismic onshore, acquire 200 square kilometres of 3D seismic offshore and two onshore wells and one offshore well by July 2013.

The Company's share of the work commitments under the first exploration periods for the three blocks is estimated at $93 million.

Madagascar

The Company has a 75 percent working interest in a PSC for a 16,845-square-kilometre block off the west coast of Madagascar with water depths ranging from shallow water to 1,500 metres. The Company completed a 31,944-line-kilometre aero-magnetic survey and a 10,000 square kilometre multi-beam survey. A 3,000-square-kilometre 3D survey began in April 2010 and will be completed in July 2010. The 3D seismic will fulfill the Phase II work commitment.

Pakistan

The Company has production sharing agreements (PSAs) for four blocks in Pakistan. The blocks are located in the Arabian Sea offshore the city of Karachi and cover a combined area of almost 10,000 square kilometres. Each agreement is for a three-Phase exploration period that ends March 2013 and a further renewal of 2 years in the event of commercial production. Phase II of the exploration period ends March 2012 and the Company has substantially completed the commitments under this phase through seismic activity. The Company will be evaluating the seismic in order to select potential drilling locations.

Capital Expenditures

For the year ended March 31, 2010 (millions of U.S. dollars)	**Exploration**	**Development**
Bangladesh	-	10
India	50	91
Indonesia(3)	39	-
Kurdistan Region	12	-
Madagascar	5	-
Pakistan	2	-
Trinidad(3)	5	-
Total(1)(2)	113	101

(1) The Company also spent $2.0 million on new ventures and other.
(2) The amounts presented are the Company's share of expenditures.
(3) Excludes the costs of the acquisitions of Black Gold Energy LLC and Voyager Energy Ltd. See "Acquisitions" in this MD&A.

Exploration

Capital spending in India during the year included the costs of drilling two wells in Cauvery, appraisal drilling on six wells in NEC-25, appraisal drilling on seven wells in the D6 Block, one well at Hazira and seismic work in the D4 Block.

Spending in Indonesia was for the ongoing 2D and 3D seismic programs, signing bonuses for the blocks awarded during the year and other block-related-expenditures.

Costs incurred in the year for Kurdistan include seismic costs, drilling preparation costs and the cost of various bonuses required as per the PSC.

Costs incurred in Madagascar were for the acquisition and reprocessing of existing 2D seismic data, the multi-beam survey and carrying costs of the block.

Spending in Pakistan was for processing of the 3D seismic survey acquired in the previous fiscal year and carrying costs of the blocks.

Capital spending in Trinidad during the year was for the bonuses required as per the PSC and carrying costs of Block 2AB.

Development

Bangladesh development spending in the year was for facilities upgrades, the workover of the Bangora-3 well, well testing and payment of the guarantee associated with the work commitment for the block.

Indian development spending in the year included well completions and connecting wells to the offshore platform for the D6 gas development and drilling the MA6H and MA7H wells, completions and connecting wells to the FPSO for the D6 oil development.

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ACQUISITIONS

On December 30, 2009, the Company acquired all of the outstanding shares of Black Gold Energy LLC for a purchase price of $280 million, which is net of $21 million of cash of Black Gold Energy LLC at acquisition. The purchase price was based on the fair value of the consideration provided using the purchase method of accounting. The assets acquired include $21 million cash and cash equivalents, $9 million restricted cash, $2 million accounts receivable, $7 million accounts payable and $481 million of property and equipment. A future income tax liability of $205 million was recorded with respect to the acquisition. The acquisition was funded primarily with convertible debentures.

On March 25, 2010 the Company issued 397,379 common shares of the Company to the former shareholders of Voyager Energy Ltd. (VEL) in exchange for all of the outstanding shares of VEL. VEL holds interests in three exploration areas in Trinidad. The purchase price was based on the fair value of the consideration provided using the purchase method of accounting. The assets acquired include $8 million cash and cash equivalents, $0.3 million accounts receivable, $5 million accounts payable and $60 million of property and equipment. A future income tax liability of $23 million was recorded with respect to the acquisition.

SEGMENT PROFIT

INDIA

Years ended March 31,	**2010**	2009
Natural gas revenue	**238,274**	45,509
Oil revenue(1)	**34,359**	8,715
Royalties	**(14,900)**	(4,666)
Profit petroleum	**(9,184)**	(6,224)
Operating expenses	**(25,129)**	(7,314)
Depletion, depreciation and accretion	**(72,976)**	(22,040)
Current income tax expense	**(24,315)**	(5,138)
Future income tax recovery	**20,410**	-
Segment profit(2)	**146,539**	8,842
Daily natural gas sales (Mcf/d)	**157,987**	24,642
Daily oil sales (bbls/d)(1)	**1,300**	410
Operating costs ($/Mcfe)	**0.42**	0.73
Depletion rate ($/Mcfe)	**1.16**	2.14

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

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

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

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Revenue and Royalties

Natural gas production from the Dhirubhai 1 and 3 gas fields in the D6 Block commenced in April 2009, resulting in a $200 million increase in revenues year-over-year. Production for the year averaged 139 MMcf/d. The contracted sales price includes a gas price of $4.20/MMBtu net and a marketing margin earned of $0.135/MMBtu, resulting in a sales price of $3.95/Mcf. Natural gas production from the Surat and Hazira fields decreased 9 percent and 28 percent, respectively, when compared to the prior year due to natural declines in these fields.

Oil production from the MA field in the D6 Block commenced in September 2008. Sales during the year averaged 1,096 bbls/d and increased revenues by $25 million compared to the prior year. Oil production from the Hazira block averaged 204 bbls/d in the year compared to 169 bbls/d in the prior year. The average oil sales price for the blocks in the year was $72.46/bbl compared to $58.62/bbl in the prior year. Oil prices moved in accordance with world market prices.

The increase in royalties is a result of the commencement of revenues from the D6 Block since the prior year's quarter. Royalties applicable to production from the D6 Block are 5 percent for the first seven years of production and gas royalties applicable to the Hazira and Surat fields are currently 10 percent of the sales price.

Profit Petroleum

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

For the D6 Block, the Company is able to use up to 90 percent of profits to recover costs. The government was entitled to 10 percent of the profits not used to recover costs during the year. Profit petroleum during the year with respect to the D6 Block was $2.3 million, which is one percent of revenues, and will continue at this level until the Company has recovered its costs.

For Hazira, in the quarter and the prior year's quarter, the government was entitled to 25 percent of the profits.

For Surat, the Company recovered its investment in the last quarter of the prior year and began sharing profits with the government at a rate of 20 percent.

The net increase in profit petroleum in the quarter and year-to-date was primarily a result of profit petroleum payments commencing for Surat and D6 and was partially offset by decreased profit petroleum payments for Hazira due to lower gas production than in the prior year.

Operating Expenses

Operating expenses in the year increased with the commencement of D6 production. On a unit of production basis, average operating expenses have decreased from the prior year with the addition of D6 production, which has an operating expense lower than that of Hazira and Surat.

Depletion, Depreciation and Accretion

The depletion rate per Mcfe decreased in the year due to the inclusion of the capital costs and the reserves attributed to the D6 Block in the calculation for the Indian cost base. The undepleted capital costs per Mcfe are less for the D6 Block than for the Hazira and Surat fields.

Income Taxes

The increase in current income tax expense in the year is primarily a result of the current income tax expense related to minimum alternative tax on the profits from the D6 Block, which commenced since the prior year. Largely offsetting current taxes for the Hazira, Surat and D6 blocks was a future income tax recovery for a tax credit available for future years related to minimum alternative tax paid in the current year.

The Company has a contingency related to income taxes as at March 31, 2010. Refer to the consolidated financial statements and notes for the period ended March 31, 2010 for a complete discussion of the contingency.

BANGLADESH

Years ended March 31,	**2010**	2009
Natural gas and condensate revenue	**60,869**	49,950
Profit petroleum	**(20,350)**	(16,639)
Operating and pipeline expenses	**(5,820)**	(4,606)
Depletion, depreciation and accretion	**(26,454)**	(21,024)
Current income tax expense	**(41)**	166
Segment profit(1)	**8,204**	7,847
Daily natural gas sales (Mcf/d)	**69,369**	57,607
Operating costs ($/Mcfe)	**0.23**	0.21
Depletion rate ($/Mcfe)	**1.03**	0.99

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

Revenue, Profit Petroleum, Depletion and Operating Expenses

Overall, Bangladesh revenue increased as a result of facility upgrades at Block 9 and the Bangora-3 well, which came on-stream in June 2009. The Company received 66.67 percent of production from Block 9 during the period in which it was recovering amounts paid in relation to the Government of Bangladesh's carried interest in the block. The amounts were fully recovered in November 2009 and the Company's share of production is now 60 percent.

Pursuant to the terms of the PSC for Block 9, the Government of Bangladesh was entitled to 61 percent of profit gas in the quarter and prior year's quarter. Profit petroleum expense increased due to increased revenues from Block 9.

Operating costs and depletion expense increased primarily as a result of increased production from Block 9 and were similar year-over-year on a unit-of-production basis.

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NETBACKS

The following tables outline the Company's operating, funds from operations and earnings netbacks (all of which are non-GAAP measures) for the years ended March 31, 2010 and 2009:

Years ended March 31,			**2010**			2009
	India ($/Mcfe)	**Bangladesh ($/Mcfe)**	**Total ($/Mcfe)**	India ($/Mcfe)	Bangladesh ($/Mcfe)	Total ($/Mcfe)
Oil and natural gas revenue	**4.51**	**2.39**	**3.88**	5.48	2.36	3.37
Royalties	**(0.25)**	**-**	**(0.17)**	(0.47)	-	(0.15)
Profit petroleum	**(0.15)**	**(0.80)**	**(0.34)**	(0.63)	(0.79)	(0.73)
Operating expense	**(0.42)**	**(0.23)**	**(0.36)**	(0.73)	(0.21)	(0.39)
Operating netback	**3.69**	**1.36**	**3.01**	3.65	1.36	2.10
Interest and other income			**0.14**			0.36
Interest and financing expense			**(0.23)**			(0.05)
General and administrative expense			**(0.13)**			(0.23)
Realized foreign exchange (loss) gain			**(0.02)**			0.11
Current income tax expense			**(0.29)**			(0.16)
Funds from operations netback			**2.48**			2.13
Unrealized foreign exchange (loss) gain			**(0.10)**			0.15
Discount of long-term account receivable			**–**			(0.01)
Stock-based compensation expense			**(0.23)**			(0.49)
Gain (loss) on short-term investment			**0.17**			(0.79)
(Loss) on long-term investment			**–**			(0.03)
Impairment of long-term investment			**–**			(0.13)
Gain on risk management contracts			**–**			0.02
Asset impairment			**–**			(0.04)
Future income tax reduction			**0.24**			-
Depletion, depreciation and accretion expense			**(1.18)**			(1.42)
Earnings netback			**1.38**			(0.61)

The netback for India, Bangladesh and in total for the Company is a non-GAAP measure calculated by dividing the revenue and costs for each country and in total for the Company by the total sales volume for each country and in total for the Company measured in Mcfe.

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CORPORATE

Years ended March 31,	**2010**	2009
Revenues		
Interest and other income	**12,679**	11,331
Expenses		
Interest and financing	**19,843**	1,498
General and administrative	**11,069**	7,125
Foreign exchange loss (gain)	**10,154**	(8,104)
Stock based-compensation	**19,778**	15,294
(Gain) loss on short-term investments	**(14,554)**	24,380
Equity (gain) loss on long-term investment	**91**	982
Impairment of long-term investment	**–**	4,186
Asset impairment	**–**	1,258
Current income tax expense	**495**	87

Interest and Other Income

Interest and other income includes a $9.1 million adjustment related to a 36-inch pipeline that is connected to the Hazira facilities. Due to a dispute that was in arbitration, the Company had been assuming that it could not include the costs of the 36-inch pipeline for cost recovery, specifically, as a deduction in the calculation of profit petroleum. During the year, the Company was successful in arbitration and, as a result, pipeline costs will be eligible for cost recovery and the Company recognized the adjustment in the year. Interest and other income also includes $2.7 million of interest on an income tax refund. Excluding the adjustment related to the pipeline arbitration and the interest on the tax refund, interest income decreased primarily due to lower average cash balances and lower rates of interest earned during the year compared to the prior year.

Interest and Financing

In November 2008, the Company entered into a lease for a FPSO, which has been classified as a capital lease. In the current year, the Company recognized $5.4 million of lease payments as an interest cost. Interest expense on the long-term debt was $9.6 million, interest expense on the convertible debentures was $3.7 million and accretion expense on the convertible debentures was $1.1 million. Results for the prior year include FPSO related costs from November 2008 to March 2009. Interest expense on the long-term debt was capitalized in the prior year during development of the D6 gas field. The convertible debentures were issued in the current year.

General and Administrative Expense

The net increase in general and administrative expense in the year was a result of higher use of outside services as a result of increased Company activity, the increase in the annual bonus and additional staff as a result of acquisitions.

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Foreign Exchange

Years ended March 31,	**2010**	2009
Realized foreign exchange loss (gain)	**1,582**	(3,320)
Unrealized foreign exchange loss (gain)	**8,572**	(4,784)
Total foreign exchange loss (gain)	**10,154**	(8,104)

The Company's realized foreign exchange arises on the settlement of Indian-rupee denominated working capital. The gains and losses depend on the timing of settlement of individual accounts receivable and accounts payable as well as the movement in value of the Indian rupee against the U.S. dollar during the period.

The unrealized foreign exchange loss arises primarily 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. The unrealized foreign exchange loss was partially offset by a gain on translating the Indian rupee-denominated income tax receivable to U.S. dollars as a result of the weakening of the U.S. dollar against the Indian rupee.

Stock-based Compensation

There was a net increase in stock-based compensation expense in the year. Stock-based compensation expense increased as a result of an increased number of options being expensed and the increased fair value expense per stock option partially offset by a credit as a result of directors of the Company forfeiting options during the year.

The Company restated the reported stock-based compensation expense for the prior year. See note 2 to the consolidated financial statements for the year ended March 31, 2010.

Short-term Investments

The unrealized gain in the year on the investments was on marking the short-term investments to market value.

Equity Loss on Long-term Investment

From inception to June 30, 2009, the Company accounted for its investment in Vast Exploration Inc. (Vast) using the equity method whereby the investment was initially recorded at cost and the carrying value was subsequently adjusted to include the Company's pro rata share of post-acquisition earnings of the investee. The Company recorded a loss of $91,000 in the year and $1.0 million in the prior year calculated by the equity method. The Company determined that the investment was impaired during the prior year and wrote the value of the investment down to the book value of the investee's net assets resulting in an impairment loss of $4.2 million. The Company ceased to exercise significant influence during the year ending March 31, 2010. As a result, the investment became ineligible for accounting under the equity method and the Company reclassified the investment to short-term investments, with changes in its fair value being recognized in earnings.

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Income Taxes

Income taxes for the year are for the estimated Alberta tax applicable to foreign income. In the prior year's periods, there was income tax on interest income from cash balances outstanding during the periods.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2010, the Company had total restricted and unrestricted cash of $246.1 million. Of the restricted cash, $28 million will be available for use in the Fiscal 2011, $16 million will be available in Fiscal 2012 and the remaining $5 million will be available thereafter. The Company has a working capital surplus of $15 million, calculated as current assets less current liabilities, therefore has short-term liquidity.

The cash that is currently restricted in accordance with the credit facility agreement is a provision for 30 days of capital and 45 days of operating costs for Hazira, Surat, Block 9 and the Dhirubhai 1 and 3 gas field in the D6 Block and a debt service reserve account. The Company has drawn the full amount available under the credit facility of $193 million and $155 million of this amount will be repaid during Fiscal 2011.

On December 30, 2009, the Company entered into a Cdn$310 million convertible debenture credit facility (the "Debentures"). The Debentures bear a coupon rate of 5 percent and mature on December 30, 2012. The interest is paid semi-annually in arrears on January 1st and July 1st of each year. Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn$110.50 per common share until 60 days prior to the maturity date. After December 30, 2010, the Company may elect to convert all of the debentures into common shares at the conversion price in effect on that date, provided that the weighted average trading price for the prior 21 trading days exceeds Cdn$143.65 per share.

For Fiscal 2011 cash balances, cashflow from operations from the Company's existing producing properties is expected to be in excess of the operating costs, exploration costs, development costs and debt repayments disclosed in this MD&A. Cashflow from operations is affected by production levels by fluctuations in foreign exchange rates, changes in operating costs and the market price of oil. The Company has entered into gas contracts for production from the D6 Block with a gas price that is fixed for Fiscal 2011.

The contractual obligations of the Company are as follows:

		Payments due by Period			
As at March 31, 2010	Total	Less than 1 year	1 – 3 Years	4 – 5 Years	After 5 Years
Principal repayments on long-term debt(1)	192,814	154,811	38,003	-	-
Guarantees(2)	26,970	25,470	1,500	-	-
Work commitments(3)	322,000	12,000	192,000	78,000	40,000
Asset retirement obligations(4)	72,269	-	267	6,619	65,383
Capital lease obligations(5)	90,562	10,757	21,514	21,514	36,777
Convertible debentures(6)	305,238	-	305,238	-	-
Total contractual obligations	1,009,853	203,038	558,522	106,133	142,160

(1) The Company is required to make repayments of the outstanding balance if the loan exceeds the amount specified in a reduction schedule or in order to bring financial coverage ratios within specified limits. Based on cashflow estimates using the current volume of gas contracts, the Company will be required to pay $155 million in fiscal 2011 in order to maintain the field life coverage ratio specified in the facility agreement.

(2) The guarantees were amended subsequent to March 31, 2010. As at June 23, 2010, the guarantees for commitments less than one year increased to $28 million. The guarantees are cancelled when the Company completed the work required under the exploration period.

(3) Details of the work commitments by property are included in "Background on Properties" in this MD&A.

(4) Asset retirement obligations are based on the undiscounted estimated future liability of the Company as disclosed in the notes to the consolidated financial statements for the year ended March 31, 2010. They do not include wells or facilities that were not complete as at March 31, 2010.

(5) Capital lease obligation includes both the current and long-term portions.

(6) The convertible debentures outstanding of Cdn$310 million were converted to U.S. dollars for the purposes of the table above at the March 31, 2010 rate of 1.0156 Cdn$ = 1 US$. The convertible debentures are recorded in the consolidated financial statements for the year ended March 31, 2010 at a value of $291.1 million.

SELECTED ANNUAL INFORMATION

Years ended March 31,	**2010**	2009	2008
Oil and natural gas revenue	**334,111**	104,993	101,006
Net income (loss)	**118,788**	(18,867)	(16,624)
Per share basic ($)	**2.39**	(0.38)	(0.36)
Per share diluted ($)	**2.37**	(0.38)	(0.36)
Total assets	**2,246,454**	1,467,063	1,315,948
Total long-term financial liabilities	**640,404**	278,342	201,921
Dividends per share (Cdn$)	**0.12**	0.12(1)	0.12

(1) The dividend of Cdn$0.03 per share related to the quarter ended March 31, 2009 was declared in April 2009.

There was a 4 percent increase in oil and natural gas revenue in Fiscal 2009 primarily as a result of the sale of first oil production from the D6 block and increased production from Block 9. Gas production from the D6 Block commenced in Fiscal 2010 contributing to the 218 percent increase in revenue in Fiscal 2010.

ALL AMOUNTS ARE IN THOUSANDS OF U.S DOLLARS UNLESS OTHERWISE INDICATED 29

Overall, there was not a significant change in revenues, royalties, profit petroleum and operating costs from Fiscal 2008 to Fiscal 2009. Interest and other income decreased from Fiscal 2008 to Fiscal 2009 primarily as a result of lower interest rates and lower cash balances in the period. There was a significant loss on the short-term investment, which was consistent with the overall market decline from Fiscal 2008 to Fiscal 2009. In addition, there was an impairment of the long-term investment for the same reason. The net loss in Fiscal 2008 was affected by the write-off of Thailand assets of $22.8 million, while only $1.3 million of assets were written off in Fiscal 2009. Please see “Overall Performance” in this MD&A for a discussion of the change from net loss in Fiscal 2009 to net income in Fiscal 2010.

Total assets increased in Fiscal 2009 over Fiscal 2008 as the increase in capital assets was partially offset by the decrease in cash and cash call advances, which were used to fund capital asset and investment additions and part of the income tax receivable was collected during the year. In Fiscal 2010, there was an unrealized gain increasing the value of the short-term investments, an increase in accounts receivable from the sale of D6 gas, an increase in the future income tax asset as a result of minimum alternative taxes paid for the D6 Block and the addition of property, plant and equipment including exploration and development expenditures and the acquisition of Black Gold Energy LLC.

Total long-term financial liabilities consisted of the asset retirement obligation and the long-term portion of debt in Fiscal 2008. In Fiscal 2009, the amount also included the capital lease obligation. In Fiscal 2010, a portion of the debt and capital lease obligation was moved to current, the convertible debentures were issued and future income tax liabilities were recorded on the acquisitions of Black Gold Energy LLC and Voyager Energy Ltd.

SUMMARY OF QUARTERLY RESULTS

The following tables set forth selected financial information of the Company for the eight most recently completed quarters to March 31, 2010:

Three months ended	June 30, 2009	Sept. 30, 2009	Dec. 31, 2009	**Mar. 31, 2010**
Oil and natural gas revenue	53,853	77,879	91,757	**110,622**
Gain (loss) on short-term investments	18,003	19,685	(26,525)	**3,391**
Net income (loss)	20,441	45,043	14,637	**38,667**
Per share				
Basic ($)	0.41	0.91	0.29	**0.77**
Diluted ($)	0.41	0.90	0.29	**0.76**

Three months ended	June 30, 2008	Sept. 30, 2008	Dec. 31, 2008	Mar. 31, 2009
Oil and natural gas revenue	24,381	24,064	28,045	28,503
Gain (loss) on short-term investment	6,875	(22,046)	(8,898)	(311)
Net income (loss)(1)	7,025	(21,575)	(1,164)	(3,153)
Per share				
Basic ($)(1)	0.14	(0.44)	(0.02)	(0.06)
Diluted ($)(1)	0.14	(0.44)	(0.02)	(0.06)

(1) Restated. See note 2 to the consolidated financial statements for the year ended March 31, 2010.

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Net income has fluctuated over the quarters, due in part to changes in revenue, interest and other income, operating expenses, profit petroleum, depletion expense, interest expense, the value of the short and long-term investments and income taxes.

Revenues have increased over the quarters as a result of increased production in Block 9 and the D6 Block. In the quarter ended December 31, 2008, revenues increased due to an increase in production from Block 9 as a result of the completion of a plant upgrade as well as the first sale of oil from the D6 Block. Gas production from the D6 Block commenced in the quarter ended June 30, 2009 and ramped-up during the subsequent three quarters, substantially increasing revenues in all four quarters. Operating expense and depletion expense increased in the same quarters as a result of the increased production. Profit petroleum expense increased in the quarter ended December 31, 2008 with the increase in revenues from Block 9.

Interest and other income in the quarter ended December 31, 2009 includes a $9.1 million adjustment related to a 36-inch pipeline that is connected to the Hazira facilities. Due to a dispute that was in arbitration, the Company had been assuming that it could not include the costs of the 36-inch pipeline for cost recovery, specifically, as a deduction in the calculation of profit petroleum. During the quarter, the Company was successful in arbitration and, as a result, pipeline costs will be eligible for cost recovery and the Company recognized the adjustment in the quarter.

Interest expense on the long-term debt was capitalized until the commencement of gas production from the D6 Block. In the quarter ended June 30, 2009, interest expense on the long-term debt was expensed, decreasing net income. In the quarter ended March 31, 2010, interest and financing expense increased with interest paid and accretion on the convertible debentures.

In the quarter ended December 31, 2008, net income was reduced by $4.2 million as the Company wrote the value of the long-term investment down to the Company's share of the book value of the investee's net assets. The Company made purchases of securities in Fiscal 2008 and Fiscal 2009. The short-term investments are recognized at fair value, which is the publicly quoted market value, and the Company recognizes gains and losses based on the changing market prices. The magnitude of the gains and losses compared to net income by quarter is displayed in the table above.

FOURTH QUARTER

During the quarter ended March 31, 2010, funds from operations was $68.8 million compared to $68.8 million in the quarter ended December 31, 2009 (previous quarter).

Revenues increased during the quarter primarily as a result of the ramp-up in production volumes from the D6 block. The increase in revenues in the quarter was offset by an increase in interest and financing expense due to interest and financing costs of the convertible debentures, which were issued on December 30, 2009 and lower other income. Other income in the previous quarter included a US$9.1 million adjustment related to a 36-inch pipeline connected to the Hazira facilities as discussed in "Summary of Quarterly Results" in this MD&A.

Net income in the quarter was $38.7 million compared to $14.6 million in the previous quarter. There was a unrealized gain on the short-term investments of $3.4 million in the quarter compared to a loss in the previous quarter of $26.5 million. Depletion expense increased with increased production volumes and the future income tax recovery increased as additional minimum alternative tax was paid in India, which is deductible against income taxes in future years.

The correction of the stock-based compensation expense reported in the three quarters ended December 31, 2009 was recognized in the fourth quarter resulting in a $1.7 million downward adjustment to stock-based compensation expense. See note 2 to the consolidated financial statements for details of the restatement.

RELATED PARTIES

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

FINANCIAL INSTRUMENTS

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

The Company is exposed to fluctuations in the value of its cash, accounts receivable, short-term investments, accounts payable and accrued liabilities due to changes in foreign exchange rates as these financial instruments are partially or wholly denominated in Canadian dollars, Indian rupees and Bangladeshi taka. The Company manages the risk by converting cash held in foreign currencies to U.S. dollars as required to fund forecast expenditures. The Company is exposed to changes in foreign exchange rates as the future interest payments on the convertible debentures are in Canadian dollars. The Company is exposed to changes in the market value of the short-term investments. The Company is exposed to changes in the LIBOR rate on the long-term debt. The Company is exposed to credit risk with respect to all of its financial instruments if a customer or counterparty fails to meet its contractual obligations. The Company has deposited the cash and restricted cash with reputable financial institutions, for which management believes the risk of loss to be remote. The Company takes measures in order to mitigate any risk of loss with respect to the accounts receivable, which may include obtaining guarantees.

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

The fair values of accounts receivable, accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The fair value of the short-term investments is based on publicly quoted market values. An unrealized gain on the recognition of the short-term investments at fair value of $14.6 million in the year was recognized in income. The fair value of the long-term account receivable is calculated based on the amount receivable discounted at 6.5 percent for three years as collection is assumed in three years. The loss on recognition of the fair value of the long-term account receivable of $0.2 million in the year was recognized in income. 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 $14.8 million. The fair value of the conversion feature of the debentures was determine based on the discounted future payments using a discount rate of a similar financial instrument without a conversion feature compared to the fixed rate of interest on the debentures. Interest and financing expense of $4.9 million was recorded for interest paid and accretion of the discount on the convertible debentures during the year. The fair value of the long-term debt is the amount of funds received by the Company. Interest expense of $9.6 million was recorded on the long-term debt during the year.

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.

Oil and Natural Gas Reserves

Reserves estimates can have a significant effect on net earnings as a result of their impact on the depletion rate, asset retirement provisions and asset impairments. Independent qualified engineers in conjunction with the Company's reserve engineers estimate the value of oil and natural gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgement. Estimates of economically recoverable oil and gas reserves and future cash flows from those reserves are based upon a number of variables and assumptions such as geological interpretation, commodity prices, operation and capital costs and production forecasts, all of which may vary considerable from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

Depletion, Depreciation and Amortization

The Company follows the full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country (full cost pool). Costs capitalized include land acquisition costs, geological and geophysical expenses, costs of drilling productive and non-productive wells, costs of gathering and production facilities and equipment and administrative costs related to capital projects. Costs capitalized in the full cost pool, including capital leases, are depleted using the unit-of-production method by cost centre based upon gross proved oil and natural gas reserves and management's best estimate of future prices and future development costs.

Revisions to reserve estimates and the associated future cashflows could significantly increase or decrease depletion expense charged to net income and could result in an impairment of property and equipment charged as an expense to net income.

Costs of acquiring unproved properties are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the full cost pool. Costs of major development projects are initially excluded from the full cost pool and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of production or the property is considered to be impaired, the cost or an appropriate portion of the cost of the property is added to the full cost pool.

A change in any of the qualitative considerations for impairment including, but not limited to: geological interpretations, exploration activities and success or failure, the Company's plans with respect to the property and financial ability to hold the property; and the lease term for the property, may result in the inclusion of the property and equipment in the full cost pool. This could significantly increase depletion expense charged to net income.

Asset Impairment

The Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property, plant and equipment. If the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate. A change in estimate of the oil and natural gas reserves as described above in "Oil and natural gas reserves", a change in the expected future prices and costs or a change in the risk-free interest rate could result in a material decrease in the fair value of the asset. This would result in a downwards adjustment to property, plant and equipment and equivalent impairment of property, plant and equipment charged as an expense to net income.

Asset Retirement Obligation

The Company recognizes the fair value of the liabilities for asset retirement obligations related to its long-lived assets in the period in which they are incurred. The fair value of an asset retirement obligation is recorded as a liability. The fair value is determined by preparing a cost estimate, inflating the costs to the expected date of abandonment and discounting the costs using a credit-adjusted risk-free rate. A change to any of the cost estimate, the inflation rate, the timing of expected abandonment or the credit-adjusted risk-free rate could result in a material change in the estimate. This would affect property, plant and equipment and asset retirement obligation recorded on the balance sheet and depletion, depreciation and accretion expense charged to net income.

Income Taxes

The Company estimates current and future income taxes based on its interpretation of tax laws in the various jurisdictions in which it operates and pays income taxes. The Company recorded its income tax expense including provisions that provide for a tax holiday deduction for various undertakings related to the Hazira and Surat for the taxation years 1998 to 2008. Should the tax authorities determine that the tax holiday deduction does not apply to natural gas, the Company would pay additional cash taxes, have a write off of the net income tax receivable on the balance sheet and recognize additional income tax expense as a charge to net income. This may also impact the oil and natural gas reserves and asset impairment related to these properties. See note 25 to the consolidated financial statements for further discussion.

ACCOUNTING CHANGES IN FISCAL 2010

Effective April 1, 2009, the Company adopted the new accounting standard, Section 3064 “Goodwill and Intangible Assets”, issued by the Canadian Institute of Chartered Accountants, replacing Sections 3062 “Goodwill and Other Intangible Assets” and Section 3450 “Research and Development Costs”.

Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. Adoption of this section did not have an impact on the Company’s consolidated financial statements.

Effective March 31, 2010, the Company adopted the amendments to Section 3862 “Financial Instruments – Disclosures”, issued by the Canadian Institute of Chartered Accountants. The amendments include enhanced disclosures relating to the fair value of financial instruments and liquidity risk associated with the financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to note 21 to the consolidated financial statements for the year ended March 31, 2010 for enhanced fair value disclosures and liquidity risk disclosures.

NEW ACCOUNTING STANDARDS

Effective April 1, 2011, the Company will adopt new accounting standards issued by the Canadian Institute of Chartered Accountants including sections 1582 “Business Combinations”, 1601 “Consolidated Financial Statements” and 1602 “Non-controlling interests”. These standards replace the existing business combination guidance and section 1600 “Consolidated Financial Statements”. Earlier adoption is permitted, provided all three standards are adopted simultaneously.

Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at the fair value of the shares at the acquisition date. In addition, the guidance generally requires all acquisition costs to be expensed whereas they could be capitalized as part of the purchase price under the previous standard. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts as was the case under the previous standard. Section 1601 establishes the standards for the preparation of Consolidated Financial Statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The adoption of these recommendations is not expected to have a material impact on the Company’s consolidated financial statements.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards (IFRS)

In February 2008, the Accounting Standards Board confirmed that IFRS will be required for interim and annual reporting by publicly accountable enterprises effective for January 1, 2011 including 2010 comparative information. IFRS will replace Canadian generally accepted accounting principles. The first interim consolidated financial statements reported under IFRS will be for the quarter ending June 30, 2011.

The Company has developed a changeover plan to complete the transition to IFRS by April 1, 2011, which is the date of transition for the Company. The conversion plan includes the following phases:

- Phase I Scoping and diagnostic – designating resources to the project, raising awareness and performing high level diagnostic assessments of accounting differences between IFRS and Canadian GAAP;
- Phase II Detailed Assessment – based on items identified in Phase I, performance of systematic and detailed analysis of gaps between the application of current accounting policies and IFRS and consider transitional policy choices. Assessment of impacts on the Company’s debt agreements, management reporting systems and business activities;
- Phase III Design and implementation – implementation of all changes approved in the assessment phase. Parallel running of Fiscal 2011 financial results and the preparation of IFRS financial statements and disclosures; and
- Phase V Evaluation – review of processes and controls to make any required changes.

The Company has completed the scoping and diagnostic phase and has completed the analysis under Phase II, but has not selected from available accounting policy alternatives. As a result, management is unable to quantify the impact of adopting IFRS on its financial statements.

IFRS 1, "First-Time Adoption of International Financial Reporting Standards" (IFRS1), provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to the general requirement for full retrospective application of IFRS. The potentially relevant exemptions that are available to the Company are as follows:

- an exemption from retroactively recognizing stock-based compensation expense in accordance with IFRS2 *Share-based Payment* on stock options that were granted on or before November 7, 2002 or those vesting prior to the date of transition to IFRSs. The Company has recognized stock-based compensation expense calculated in accordance with Canadian GAAP for options granted subsequent to April 1, 2003.
- an exemption from retroactively restating the value of property, plant and equipment. An entity may elect to measure an item of property, plant and equipment at the date of transition at the value under its previous GAAP.
- an exemption from applying IFRIC1 *Changes in Existing Decommissioning, Restoration and Similar Liabilities* for changes that occurred before the date of transition to IFRSs. Instead, the Company may measure the liability at the date of transition to IFRSs, discount the liability to date of inception and calculate the accumulated depreciation on that amount.

The following major differences between Canadian GAAP and IFRS could be significant to the Company:

- IFRS 2 *Share-based Payment*: Similar to Canadian GAAP, under IFRS2 the fair value of the compensation expense associated with the Company's stock option plan will be recognized as an expense with a corresponding increase in equity. The Company's stock options are equity settled. The Company currently estimates a forfeiture rate of nil percent and subsequently adjusts the expense as forfeitures occur. Under IFRS2, the Company will estimate a forfeiture rate that will be considered in the fair value of the stock options.

- IFRS 6 *Exploration for and Evaluation of Mineral Resources* applies to the Company's exploration expenditures.

  The Company currently capitalizes expenditures prior to obtaining the legal right to explore under its Canadian GAAP policy while these costs will be expensed under IFRSs. In addition, there are options to capitalize or expense and amortize or not amortize exploration and evaluation costs.

- IAS16 *Property, Plant and Equipment* applies to the Company's development and production assets.

  The Company currently capitalizes costs of development and production assets that meet the definition of an asset under Canadian GAAP and depletes these costs by cost centre, which is a country, based on total proved reserves. Under IFRS, the depletion rate will be calculated at the cash-generating-unit (CGU) level, which is the smallest group of assets capable of independently generating cash inflows. In addition, there are options to expense certain costs in the development and production phase and an option to use a different reserve base in the depletion calculation.

- IAS 36 *Impairment of Assets* requires the Company to assess whether there is any indication that an asset may be impaired at the end of each reporting period. If any such indication exists, the Company will estimate the recoverable amount of the asset.

  Under Canadian GAAP, the impairment test is applied to the cost centre level, whereas it will be applied to CGUs under IFRS. In addition, the method of calculating the impairment differs.

- IAS 37 *Provisions, Contingent Liabilities & Contingent Assets* indicates how to identify and calculate these items, including asset retirement obligations (ARO). The discount rates applied to estimate future cashflows differ under Canadian GAAP and IFRSs. In addition, ARO is required to be revalued each reporting period at the then prevailing interest rate.

- IAS 12 *Income Taxes* differs from Canadian GAAP for purposes of recognizing deferred taxes, specifically in relation to intercompany transfers, asset acquisitions, foreign currency and other minor items.

Other areas that the Company has determined may have different results in the financial statements under IFRSs than under Canadian GAAP include leases and employee benefits. This list of areas impacted by IFRS should not be regarded as a comprehensive list of changes that will result from the transition to IFRS. The Company continues to monitor the development of standards. At this time, the Company has not selected its accounting policies under IFRS.

In addition to accounting policy differences, the Company's transition to IFRS will impact information technology and data systems; internal control over financial reporting, disclosure controls and procedures, financial reporting expertise, and business activities as follows:

- IT systems – The Company's accounting software does not support the conversion to IFRS. The Company expects to maintain the accounts under Canadian GAAP and IFRS during the conversion process.
- Internal control over financial reporting (ICOFR) – Once the accounting policy choices are selected and approved, the Company will assess the changes required for ICOFR. Some of the controls previously performed in Canada are expected to be performed in the branch offices and additional controls are expected to be implemented over the conversion process.
- Disclosure controls and procedures (DCP) – The Company anticipates providing information to stakeholders as per the requirements and recommendations of the security regulators through regulatory documents including this and future MD&As.
- Financial reporting expertise – The Company's staff responsible for financial reporting have been attending outside courses, seminars and updates on IFRS. The Company has scheduled in-house IFRS training for 2010 to update and augment the knowledge of the staff. In addition, the Company attends an IFRS group with its peers to discuss accounting policy choices and implementation issues. Finally, the Company monitors exposure drafts and updates to IFRS on an ongoing basis.
- Business activities – The Company has long-term debt and convertible debentures with financial covenants. Both agreements provide for the conversion to IFRS as acceptable accounting principles upon which to base the financial information used in the covenants and the financial information to be provided as per the agreements.

DISCLOSURE CONTROLS AND PROCEDURES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision and evaluating the effectiveness of the Company's internal controls over financial reporting. The Chief Executive Officer and Chief Financial Officer have overseen the design and evaluation of internal controls over financial reporting and have concluded that, except as noted below, 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 Canadian GAAP.

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 the internal controls over financial reporting during the year ended March 31, 2010 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. Due to the material weakness determined in preparation of the consolidated financial statements, the Company will consider additional controls required in the coming year.

During the preparation of the consolidated financial statements for the year ended March 31, 2010, the Company identified an accounting error related to an overstatement of stock-based compensation expense for the periods up to and including December 31, 2009. As a result, the Company determined that there was a material weakness in the design of its internal controls over financial reporting with respect to stock-based compensation. The Company applied the correct model to options with a single expiry date, however, the Company applied the incorrect Black-Scholes model to grants of options with multiple expiry dates. The Company has reviewed the Black-Scholes models being used for the various types of options granted and in order to remediate this weakness will conduct this review on an annual basis. The Company adjusted the error for April 1 to December 31, 2009 in the current year. The Company has restated its consolidated financial statements for the year ended March 31, 2009 and has adjusted the error for April 1 to December 31, 2009 in the current year.

RISK FACTORS

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

- The Company may not be able to find reserves at a reasonable cost, develop reserves within required time-frames or at a reasonable cost, or sell these reserves for a reasonable profit;
- Reserves may be revised due to economic and technical factors;
- The Company may not be able to obtain approval, or obtain approval on a timely basis for exploration and development activities;
- Changing governmental policies, social instability and other political, economic or diplomatic developments in the countries in which the Company operates;
- Changing taxation policies, taxation laws and interpretations thereof;
- Changes in the timing of future debt repayments based on provisions in the Company's loan agreement;
- 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 March 31, 2010. 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 June 23, 2010, the Company had the following outstanding shares:

	Number	Cdn$ Amount(1)
Common shares	**50,949,797**	**$ 1,300,140,000**
Preferred shares	**nil**	**nil**
Stock options	**4,111,652**	**–**

(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 June 23, 2010 is $1,117,579,000.

ALL AMOUNTS ARE IN THOUSANDS OF U.S DOLLARS UNLESS OTHERWISE INDICATED

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all other information contained elsewhere in this report is the responsibility of the management of Niko Resources Ltd. The consolidated financial statements necessarily include amounts that are based on estimates, which have been objectively developed by management using all relevant information. The financial information contained elsewhere in this report has been reviewed to ensure consistency with the consolidated financial statements.

Management maintains and evaluates the effectiveness of disclosure controls and procedures and internal control over financial reporting for Niko Resources Ltd. Disclosure controls and procedures are designed to provide reasonable assurance that material information relating to Niko Resources Ltd., including its consolidated subsidiaries, is made known to management by others within those entities. Internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with Canadian generally accepted accounting principles. The Company evaluates the effectiveness of internal controls over financial reporting at the financial year end and discloses its conclusions about the effectiveness in the Company's annual management's discussion and analysis (MD&A).

The Audit Committee of the Board of Directors, comprised of non-management directors, has reviewed the consolidated financial statements with management and the auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

The consolidated financial statements have been audited by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

(signed) "Edward S. Sampson"
Edward S. Sampson
President and CEO
June 23, 2010

(signed) "Murray Hesje"
Murray Hesje
Vice President, Finance and CFO

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Niko Resources Ltd. as at March 31, 2010 and 2009 and the consolidated statements of operations, comprehensive income (loss) and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2010 and 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed) "KPMG LLP"
Chartered Accountants
Calgary, Canada
June 23, 2010

CONSOLIDATED BALANCE SHEETS

As at March 31,	**2010**	2009 Restated (note 2)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 196,813**	$ 31,189
Restricted cash (note 5)	**28,245**	185,475
Short-term investment (note 3c)	**32,081**	9,067
Accounts receivable	**47,706**	20,287
Inventory	**256**	616
Prepaid expenses and deposits	**724**	1,494
	305,825	248,128
Restricted cash (note 5)	**21,026**	24,011
Long-term investment (note 6)	**-**	4,216
Long-term accounts receivable (note 7a)	**31,128**	22,201
Income tax receivable (note 7b)	**23,240**	16,000
Future income tax asset (note 17)	**20,410**	–
Property, plant and equipment (note 9)	**1,844,826**	1,152,507
	$ 2,246,455	$ 1,467,063
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 123,547**	$ 119,555
Current tax payable	**1,971**	2,691
Current portion of capital lease obligation (note 24b)	**10,757**	10,752
Current portion of long-term debt (note 11, 21)	**154,811**	–
	291,086	132,998
Asset retirement obligation (note 10)	**30,520**	27,544
Capital lease obligation (note 24b)	**53,072**	57,984
Long-term debt (note 11, 21)	**38,003**	192,814
Convertible debentures (note 12)	**291,063**	–
Future income tax liability (note 17)	**227,746**	–
	931,490	411,340
Shareholders' equity		
Share capital (note 13)	**1,107,163**	997,189
Contributed surplus (note 14)	**48,397**	41,494
Equity component of convertible debentures (note 12)	**14,765**	–
Accumulated other comprehensive income (loss) (note 15)	**12,220**	(2,406)
Retained earnings	**132,420**	19,446
	1,314,965	1,055,723
	$ 2,246,455	$ 1,467,063

Segmented information (note 19)
Capital management (note 20)
Guarantees (note 22)
Related-party transactions (note 23)
Commitments and contractual obligations (note 24)
Contingencies (note 25)
See accompanying Notes to Consolidated Financial Statements.

ALL AMOUNTS ARE IN THOUSANDS OF U.S. DOLLARS UNLESS OTHERWISE INDICATED

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME (LOSS) AND RETAINED EARNINGS

Years ended March 31,		**2010**		2009 Restated (note 2)
Revenue				
Oil and natural gas	**$**	**334,111**	$	104,993
Royalties		**(14,979)**		(4,801)
Profit petroleum		**(29,533)**		(22,863)
Interest and other		**12,679**		12,143
		302,278		89,472
Expenses				
Operating and pipeline		**31,125**		12,367
Interest and financing (note 16)		**19,843**		1,498
General and administrative		**11,069**		7,125
Foreign exchange loss (gain)		**10,154**		(8,104)
Discount of long-term account receivable (note 7a)		**176**		265
Stock-based compensation (note 13c)		**19,778**		15,294
(Gain) loss on short-term investment		**(14,554)**		24,380
Equity loss on long-term investment (note 6)		**91**		982
Impairment of long-term investment (note 6)		**–**		4,186
Asset impairment		**–**		1,258
Depletion, depreciation and accretion		**101,367**		44,029
		179,049		103,280
Income (loss) before income taxes		**123,229**		(13,808)
Income tax expense (note 17)				
Current income tax expense		**24,851**		5,059
Future income tax reduction		**(20,410)**		–
		4,441		5,059
Net income (loss)	**$**	**118,788**	$	(18,867)
Net income (loss) per share (note 18)				
Basic	**$**	**2.39**	$	(0.38)
Diluted	**$**	**2.37**	$	(0.38)
Comprehensive income (loss):				
Net Income (loss)	**$**	**118,788**	$	(18,867)
Foreign currency translation gain (loss)		**14,626**		(43,395)
Comprehensive income (loss) (note 15)	**$**	**133,414**	$	(62,262)
Retained earnings, beginning of year	**$**	**19,446**	$	43,378
Net income (loss)		**118,788**		(18,867)
Dividends paid		**(5,814)**		(5,065)
Retained earnings, end of year	**$**	**132,420**	$	19,446

See accompanying Notes to Consolidated Financial Statements.

ALL AMOUNTS ARE IN THOUSANDS OF U.S. DOLLARS UNLESS OTHERWISE INDICATED

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended March 31,		**2010**		2009 Restated (note 2)
Cash provided by (used in):				
Operating activities				
Net income (loss)	**$**	**118,788**	$	(18,867)
Add items not involving cash from operations:				
Unrealized foreign exchange loss (gain)		**8,572**		(4,784)
Unrealized (gain) loss on short-term investment		**(14,554)**		24,380
Equity loss on long-term investment		**91**		982
Impairment loss on long-term investment		**–**		4,186
Discount of long-term account receivable		**176**		265
Stock-based compensation		**19,778**		15,294
Unrealized (gain) on risk management contracts		**–**		(494)
Asset impairment		**–**		1,258
Depletion, depreciation and accretion		**101,367**		44,029
Future income tax reduction		**(20,410)**		–
Change in non-cash working capital		**(26,103)**		(5,792)
Change in long-term accounts receivable		**(5,987)**		11,480
		181,718		71,937
Financing activities				
Proceeds from issuance of shares, net of issuance costs (note 13)		**54,998**		11,614
Convertible debentures		**297,590**		–
Dividends paid		**(5,814)**		(5,065)
		346,774		6,549
Investing activities				
Addition of property, plant and equipment		**(216,363)**		(481,936)
Property acquisitions (note 8)		**(302,792)**		–
Reduction in capital lease obligations		**(4,531)**		(1,111)
Restricted cash contributions		**(250,049)**		(103,914)
Restricted cash released		**418,781**		24,351
Addition to short-term investment		**–**		(19,927)
Disposition of short-term investment		**1,054**		–
Addition to long-term investment		**–**		(11,378)
Change in non-cash working capital		**(11,476)**		103,795
Change in cash call advances		**(440)**		23,421
		(365,816)		(466,699)
(Decrease) increase in cash and cash equivalents		**162,676**		(388,213)
Effect of foreign currency translation on cash and cash equivalents		**2,948**		(24,487)
Cash and cash equivalents, beginning of year		**31,189**		443,889
Cash and cash equivalents, end of year	**$**	**196,813**	$	31,189
Supplemental information:				
Interest paid	**$**	**8,315**	$	8,245
Taxes paid	**$**	**35,442**	$	5,281

See accompanying Notes to Consolidated Financial Statements.

ALL AMOUNTS ARE IN THOUSANDS OF U.S. DOLLARS UNLESS OTHERWISE INDICATED

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the year ended March 31, 2010. All tabular amounts are in thousands of U.S. dollars except per share amounts, numbers of shares and stock options, stock option and share prices, and certain other figures as indicated.

1. BASIS OF PRESENTATION

The 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 consolidated financial statements reflect only the Company’s proportionate interest in such activities.

Certain comparative figures have been reclassified to conform to the current year presentation.

2. RESTATEMENT

During the preparation of the consolidated financial statements for the year ended March 31, 2010, the Company identified an accounting error related to an overstatement of stock-based compensation expense for the periods from January 1, 2006 to December 31, 2009. The adjustment resulted in a decrease in the reported property, plant and equipment, stock-based compensation expense, share capital and contributed surplus and an increase in retained earnings. The Company adjusted the error for April 1, 2009 to December 31, 2009 in the current year. The Company has amended its consolidated financial statements for the year ended March 31, 2009 as below.

Consolidated Balance Sheet

As at March 31, 2009	Previously Reported	Adjustment	Restated
Property, plant and equipment	$ 1,154,074	(1,567)	$ 1,152,507
Share capital	$ 1,001,885	(4,696)	$ 997,189
Contributed surplus	$ 51,966	(10,472)	$ 41,494
Retained earnings, end of year	$ 5,845	13,601	$ 19,446

Consolidated Statements of Operations and Retained Earnings

For the year ended March 31, 2009	Previously Reported	Adjustment	Restated
Stock-based compensation	$ 18,989	(3,695)	$ 15,294
Net loss	$ (22,562)	3,695	$ (18,867)
Retained earnings, beginning of the year	$ 33,472	9,906	$ 43,378
Basic and diluted loss per share	$ (0.46)	0.08	$ (0.38)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) CASH AND CASH EQUIVALENTS
Cash and cash equivalents consists of cash and demand deposits.

(b) RESTRICTED CASH
Cash that is subject to restrictions that limit its use to specified current purposes is classified as restricted cash in current assets. Cash that is subject to restrictions that limit its use to specified non-current purposes is classified under restricted cash in non-current assets.

(c) SHORT-TERM INVESTMENTS
Short-term investments consist of marketable securities. The short-term investments were designated as held-for-trading upon initial recognition. See note 3(r) for a description of the accounting policy for held-for-trading financial instruments.

(d) INVENTORY
Inventories consist of oil and condensate, which are recorded at the lower of cost and net realizable value. Cost is comprised of operating expenses that have been incurred in bringing inventories to their present location and condition and the portion of depletion expense associated with the oil and condensate production. Net realizable value is the estimated selling price in the ordinary course of business less applicable variable selling expenses. The Company assigns the cost of inventory using the first-in-first out method. All inventory outstanding at the beginning of the period is sold during the period.

(e) LONG-TERM INVESTMENTS
The Company classifies investments in which it is able to exercise significant influence over an investee that is not a subsidiary as a long-term investment. Long-term investments are accounted for using the equity method whereby the investment is initially recorded at cost and the carrying value is subsequently adjusted to include the Company's pro-rata share of post-acquisition earnings of the investee. When there has been a loss in value of an investment that is other than a temporary decline, the investment is written down to recognize the loss. When the Company ceases to be able to exercise significant influence over an investee, the investment is accounted for as a financial instrument. See note 3(r) for a description of the accounting policy for financial instruments.

(f) PROPERTY, PLANT AND EQUIPMENT
The Company follows the full cost method of accounting whereby all costs related to the exploration for and development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. Costs capitalized include land acquisition costs, geological and geophysical expenses, costs of drilling productive and non-productive wells, costs of gathering and production facilities and equipment and administrative costs related to capital projects. Gains or losses are not recognized upon disposition of oil and natural gas properties unless such disposition would alter the depletion rate by 20 percent or more.

In applying the full cost method, the Company performs a cost recovery test (ceiling test), placing a limit on the carrying value of property, plant and equipment. If the carrying value exceeds the fair value, an impairment loss is recognized to the extent that the carrying value of assets exceeds the net present value, calculated as the sum of the discounted value of future net revenues from proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The net present value is estimated using expected future prices and costs and is discounted using a risk-free interest rate.

(g) DEPLETION AND DEPRECIATION

Costs of acquiring unproved properties are initially excluded from costs subject to depletion and are assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned to the property or the property is considered to be impaired, the cost of the property or the amount of impairment is added to costs subject to depletion. Costs of major development projects are initially excluded from costs subject to depletion and are assessed quarterly to ascertain whether impairment has occurred. When a portion of the property becomes capable of production or the property is considered to be impaired, the cost or an appropriate portion of the cost of the property is added to costs subject to depletion.

Costs capitalized in the full cost pool, including capital leases, are depleted using the unit-of-production method by cost centre based upon total proved oil and natural gas reserves before royalties as determined by independent engineers and updated internally as applicable. For purposes of the calculation, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content.

Office and other equipment is depreciated using the declining balance method at rates of 20 to 30 percent per annum.

(h) CAPITALIZED INTEREST

Interest costs on major capital projects are capitalized until the projects are capable of commercial production. These costs are subsequently amortized with the related assets.

(i) ASSET RETIREMENT OBLIGATIONS

The Company recognizes the fair value of the liabilities for asset retirement obligations related to its long-lived assets in the period in which they are incurred. The fair value of an asset retirement obligation is recorded as a liability with a corresponding increase in property and equipment. The increase in property and equipment is depleted using the unit-of-production method consistent with the underlying assets. The accretion expense for increases to the asset retirement obligations due to the passage of time are recognized at the end of each period. Subsequent to initial measurement, period-to-period changes in the liabilities are recognized for revisions to either the timing or the amount of the original estimates of undiscounted cash flows. Actual costs incurred upon settlement are charged against the asset retirement obligations. Any difference between the actual cost and the recorded liability is recognized as a gain or loss in net income in the period in which settlement occurs.

(j) LEASES

Leases are classified as either capital or operating in nature. Capital leases are those that transfer substantially all of the benefits and risks of ownership related to the leased property from the lessor to the lessee. Assets acquired under capital leases are depleted along with the petroleum and natural gas properties. Obligations recorded under capital leases are reduced by the principal portion of lease payments as incurred and the imputed interest portion of capital lease payments is charged to expense. Operating leases are those where the benefits and risks of ownership related to the lease property are substantially retained by the lessor. Operating lease payments are charged to expense.

(k) COMPREHENSIVE INCOME

Comprehensive income consists of net income and other comprehensive income (OCI). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge, the change in fair value of any available-for-sale financial instruments and foreign exchange gains or losses arising from the translation of Canadian operations using the current rate method to U.S. dollars. Amounts included in OCI are shown net of tax. Accumulated other comprehensive income is an equity category comprised of the cumulative amounts of OCI.

(l) REVENUE RECOGNITION

Sales of crude oil, natural gas and natural gas liquids are recorded in the period in which the title to the petroleum transfers to the customer. Crude oil and natural gas liquids produced and stored by the Company, but unsold, are recorded as inventory until sold.

The Company enters into long-term, fixed price gas sales contracts in the normal course of business. These physical sale contracts are documented as normal purchase and sale transactions and as such are not considered financial instruments. The Company accounts for these contracts as executory contracts rather than as non-financial derivatives.

(m) FOREIGN CURRENCY

The Company’s Canadian operations have the Canadian dollar as their functional currency and, as the Company reports its results in U.S. dollars, it therefore uses the current rate method of foreign currency translation. Under the current rate method, accounts are translated to U.S. dollars from their Canadian dollar functional currency as follows: assets and liabilities are translated at the exchange rate in effect at the balance sheet date, and revenues and expenses are translated at the average exchange rate for the period. Gains and losses resulting from the translation of Canadian operations to U.S. dollars are included in the foreign currency translation account within other comprehensive income.

Transactions in foreign currencies, other than the U.S. dollar, are translated at rates in effect at the time of the transaction and any resulting gains and losses are included in net income.

(n) INCOME TAXES
The Company follows the asset and liability method to account for income taxes. Under this method, future income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs. A valuation allowance is recorded against any future income tax asset if it is more likely than not that the asset will not be realized.

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

The most significant estimates made by management relate to amounts recorded for the depletion of property and equipment, the provision for the asset retirement obligation, accretion expense, the ceiling test, stock-based compensation expense and the fair value of long-term accounts receivable. The ceiling test calculation and the provisions for depletion and asset retirement obligations are based on such factors as estimated proved reserves, production rates, future petroleum and natural gas prices and future costs. Stock-based compensation is based on such factors as the risk-free interest rate, volatility, expected life, expected dividends and expected forfeiture rates. The fair value of the long-term account receivable is based on a discount rate and timing of collection. Future events could result in material changes to the carrying values recognized in the financial statements.

(p) PER SHARE AMOUNTS
Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options to purchase common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and any other dilutive instrument.

(q) STOCK-BASED COMPENSATION
The Company has a stock-based compensation plan as described in note 13. Compensation expense associated with the plan is recognized over the vesting period of the plan with a corresponding increase in contributed surplus. Compensation expense is based on the fair value of the stock options at the grant date using the Black-Scholes option-pricing model. Any consideration received upon exercise of the stock options, together with the amount previously recognized in contributed surplus, is recorded as an increase to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather, the Company accounts for actual forfeitures as they occur.

(r) FINANCIAL INSTRUMENTS

Financial instruments are initially recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held-for-trading financial assets and liabilities; loans and receivables; held to maturity investments; available-for-sale financial assets; and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Transaction costs on financial assets and liabilities classified other than as held for trading are added to the fair value upon initial recognition.

Held for trading financial assets and liabilities:
Subsequent to initial measurement, held for trading financial instruments are recorded at fair value and any unrealized gains and losses resulting from the change in fair value are recognized in net income. Cash and cash equivalents, restricted cash and short-term investments are classified as held-for-trading.

Loans and receivables:
Subsequent to initial measurement, loans and receivables are measured at cost using the effective interest rate method. Accounts receivable and long-term accounts receivable are classified as loans and receivables.

Held to maturity investments:
Subsequent to initial measurement, held to maturity investments are measured at cost using the effective interest rate method. The Company does not have any financial instruments classified as held to maturity.

Available for sale financial assets:
Subsequent to initial measurement, gains and losses on available-for-sale financial assets are recognized in other comprehensive income and transferred to net income when the asset is derecognized or impaired. The Company does not have any financial instruments classified as available for sale.

Other financial liabilities:
Subsequent to initial measurement, other financial liabilities are recognized at cost using the effective interest rate method.

4. CHANGES IN ACCOUNTING POLICIES

(a) ACCOUNTING CHANGES DURING THE YEAR

(i) Effective April 1, 2009, the Company adopted the new accounting standard, Section 3064 “Goodwill and Intangible Assets”, issued by the Canadian Institute of Chartered Accountants, replacing Sections 3062 “Goodwill and Other Intangible Assets” and Section 3450 “Research and Development Costs”.

Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Adoption of this section did not have an impact on the Company’s consolidated financial statements.

(ii) Effective March 31, 2010, the Company adopted the amendments to Section 3862 “Financial Instruments – Disclosures”, issued by the Canadian Institute of Chartered Accountants. The amendments include enhanced disclosures relating to the fair value of financial instruments and liquidity risk associated with the financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to note 21 for enhanced fair value disclosures and liquidity risk disclosures.

(b) FUTURE ACCOUNTING CHANGES

(i) Effective April 1, 2011, the Company will adopt new accounting standards issued by the Canadian Institute of Chartered Accountants including sections 1582 “Business Combinations”, 1601 “Consolidated Financial Statements” and 1602 “Non-controlling interests”. These standards replace the existing business combination guidance and section 1600 “Consolidated Financial Statements”. Earlier adoption is permitted, provided all three standards are adopted simultaneously.

Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at the fair value of the shares at the acquisition date. In addition, the guidance generally requires all acquisition costs to be expensed whereas they could be capitalized as part of the purchase price under the previous standard. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts under the previous standard. Section 1601 establishes the standards for the preparation of Consolidated Financial Statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination.

The adoption of these recommendations may have a material impact on any future business combinations or future investments reported in the Company’s consolidated financial statements.

(ii) Effective for fiscal years beginning on or after January 1, 2011, the Company will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian generally accepted accounting principles. The Company has developed a changeover plan to complete the transition to IFRS by April 1, 2011. The first unaudited interim consolidated financial statements reported under IFRS will be for the quarter ending June 30, 2011.

5. RESTRICTED CASH

As at March 31,	**2010**	2009
Current portion of restricted cash		
Guarantees(1)	**$ 21,838**	$ –
Funds restricted under the facility agreement(2)	**6,407**	185,475
Total	**$ 28,245**	$ 185,475
Non-current portion of restricted cash		
Guarantees(1)	**$ 1,500**	$ 13,463
Debt service reserve account(3)	**14,489**	7,008
Site restoration fund(4)	**5,037**	3,540
Total	**$ 21,026**	$ 24,011

(1) The Company has performance security guarantees related to the work commitments for exploration blocks. The Company is required to provide funds to support the guarantees in the amounts indicated above. See note 22 for details of the guarantees.

(2) The current portion of cash that is restricted under the facility agreement as at March 31, 2010 is restricted to payments of capital and operating costs for Hazira, Surat, Block 9 and the Dhirubhai 1 and 3 gas field in the D6 Block including amounts recorded in accounts payable and accrued liabilities and amounts to be incurred in the upcoming year. The amount of the cash that is restricted is a provision for 30 days of forecast capital costs and 45 days of forecast operating costs for these blocks. As at March 31, 2009, the amount of cash that was restricted was a provision for 50 percent of the forecast capital to complete Phase I of the Dhirubhai 1 and 3 gas field development.

(3) The Company funds the debt service reserve account for 50 percent of the forecast interest payments and debt repayments in the upcoming 6-month period in accordance with the terms of the facility agreement.

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

6. LONG-TERM INVESTMENT

The long-term investment was initially recorded at its cost of $11.4 million. An equity loss of $91,000 was recognized in the year ended March 31, 2010 (2009 – $1.0 million). The Company determined that the investment was impaired during the year ended March 31, 2009 and wrote the value of the investment down to the book value of the investee's net assets of $4.5 million resulting in an impairment loss of $4.2 million. The Company ceased to exercise significant influence during the year ended March 31, 2010 and accordingly, accounts for the investment as a held-for-trading financial instrument with changes in its fair value being recognized in earnings.

ALL AMOUNTS ARE IN THOUSANDS OF U.S. DOLLARS UNLESS OTHERWISE INDICATED 53

7. LONG-TERM ACCOUNTS RECEIVABLE

(a) Long-term Accounts Receivable

The long-term accounts receivable balance includes a receivable for the natural gas sales to the Bangladesh Oil, Gas and Mineral Corporation (Petrobangla) for production from the Feni field in Bangladesh. The Company produced natural gas from the Feni field from November 2004 to April 2010 and delivered the natural gas to Petrobangla for the duration. The Company formalized a Gas Purchase and Sales Agreement (GPSA) in the year ended March 31, 2007 at a price of $1.75 per Mcf. The GPSA expired in November 2009.

Receipt of the outstanding amount is being delayed as a result of various claims raised against the Company, which are described in note 25 (a) and (b). Although the Company expects to collect the full amount of the receivable, the timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company. As a result, the receivable has been classified as long-term and discounted using a risk-adjusted rate of 6.5 percent to reflect the delay in collection of these amounts. The receivable increased by $1.0 million discounted to $0.8 million for gas delivered in the year (2009 - $1.5 million for gas delivered discounted to $1.2 million). No amounts were collected during the year or the previous year.

(b) Income Tax Receivable

The income tax receivable balance results from advances made to the tax authority in India in excess of the original tax filing. While no assurance can be given, the Company believes it will be successful on appeal and the tax authority will refund these advances. See further discussion in note 25 (e).

(c) Pipeline at Hazira

The Company has recognized a receivable for a refund of previously paid profit petroleum and a receivable from its joint venture partner as a result of the award of ownership of a 36-inch pipeline that is connected to the Hazira facilities in the amount of $8 million. See further discussion in note 25 (g).

8. PROPERTY ACQUISITIONS

On December 30, 2009, the Company acquired all of the outstanding shares of Black Gold Energy LLC (BGE) for a purchase price of $300 million. The acquisition increased the Company’s working interest in the Indonesian exploration blocks.

On March 25, 2010 the Company issued 397,379 common shares of the Company to the former shareholders of Voyager Energy Ltd. (VEL) in exchange for all of the outstanding shares of VEL. VEL holds interests in three exploration blocks in Trinidad.

The Companies acquired hold unproven exploration properties and do not meet the definition of a business, therefore the acquisitions are not accounted for as a business combination.

On August 28, 2009, the Company acquired an additional 10% net working interest in the Qara Dagh Production Sharing Contract (PSC) in accordance with an agreement entered into with the Kurdistan Regional Government at a cost of $30 million.

The purchase prices of BGE and VEL were based on the fair value of the consideration provided, using the purchase method of accounting and were allocated as follows:

	BGE	VEL	Qara Dagh	Total
Cash and cash equivalents	$ 20,789	$ 7,650	$ –	$ 28,439
Restricted cash	8,515	–	–	8,515
Accounts receivable	1,732	335	–	2,067
Accounts payable and accrued liabilities	(6,888)	(4,508)	–	(11,396)
Property and equipment	481,391	59,652	30,000	571,043
Future income tax liability	(204,833)	(22,913)	–	(227,746)
Net assets acquired	$ 300,706[(1)]	$ 40,216[(1)]	$ 30,000	$ 370,922
Total purchase price	$ 300,706	$ 40,216	$ 30,000	$ 370,922
Less:				
Cash and cash equivalents acquired	(20,789)	(7,650)	–	(28,439)
Shares issued	–	(39,691)	–	(39,691)
Net cash paid (received)	$ 279,917	$ (7,125)	$ 30,000	$ 302,792

(1) These amounts represent the estimated fair values of the respective assets and liabilities except that the amount recorded for the future income tax liability is based on the differences between the tax basis and the amount allocated to property, plant and equipment in the purchase equation at the applicable tax rates.

Transaction costs of $0.7 million were incurred for the acquisition of BGE and $0.5 for the acquisition of VEL.

The above amounts are estimates made by management based on currently available information. Amendments may be made to the purchase price equation as the costs estimates and balances are finalized.

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9. PROPERTY, PLANT AND EQUIPMENT

As at March 31, 2010	Cost	Accumulated Depletion and Depreciation	Net Book Value	Costs not subject to Depletion and Depreciation
Oil and natural gas				
Bangladesh	**$ 216,524**	**$ 93,988**	**$ 122,536**	**$ –**
India[(1)]	**1,256,802**	**243,111**	**1,013,691**	**173,388**
Indonesia	**537,233**	**–**	**537,233**	**537,233**
Kurdistan	**67,592**	**–**	**67,592**	**67,592**
Madagascar	**9,490**	**–**	**9,490**	**9,490**
Pakistan	**24,647**	**–**	**24,647**	**24,647**
Trinidad	**65,143**	**–**	**65,143**	**65,143**
All other	**9,002**	**4,508**	**4,494**	**2,998**
Total	**$ 2,186,433**	**$ 341,607**	**$ 1,844,826**	**$ 880,491**

As at March 31, 2009	Cost	Accumulated Depletion and Depreciation	Net Book Value	Costs not subject to Depletion and Depreciation
Oil and natural gas				
Bangladesh	$ 206,058	$ 67,590	$ 138,468	$ –
India[(1)]	1,114,624	171,377	943,247	680,775
Indonesia	15,844	–	15,844	15,844
Kurdistan	24,344	–	24,344	24,344
Madagascar	4,393	–	4,393	4,393
Pakistan	22,770	–	22,770	22,770
All other	5,930	2,489	3,441	1,657
Total	$ 1,393,963	$ 241,456	$ 1,152,507	$ 749,783

(1) India property, plant and equipment includes a capital lease for the floating, production, storage and offloading vessel (FPSO) which, at March 31, 2010, had a cost of $71.4 million, accumulated depletion of $6.8 million and a net book value of $64.6 million (March 31, 2009 – cost of $71.4 million, accumulated depletion of $2.7 million and a net book value of $68.7 million). Depletion expense related to the capital lease of $4.1 million was included in the depletion, depreciation and accretion expense for the year ended March 31, 2010 (March 31, 2009 – $2.7 million).

During the year ended March 31, 2009, the Company expensed costs of $1.3 million that were previously capitalized for new ventures. These capitalized costs were related to the evaluation of potential new ventures with which the Company decided not to proceed.

During the year ended March 31, 2010, the Company capitalized $0.4 million of general and administrative expenses, $2.1 million of stock-based compensation expense and $1.0 million of financing charges (March 31, 2009 – $1.5 million of general and administrative expenses, $1.8 million of stock-based compensation expense and $11.0 million of financing charges).

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At March 31, 2010, the Company performed ceiling tests for the Indian and Bangladeshi cost centres to assess the recoverable value. The natural gas prices used in the ceiling tests were based on contracts entered into by the Company and forecast contract prices as indicated below. The future oil and condensate prices for the D6 Block and Hazira Field in India and Block 9 in Bangladesh were based on the January 1, 2010 commodity price forecast relative to Brent Blend prices of the Company's independent reserve evaluators and were adjusted for commodity price differentials specific to the Company, being 100% of Brent Blend for the D6 Block and Block 9 and 95% of Brent Blend for the Hazira Field.

The table below summarizes the benchmark and forecast prices used in the ceiling test calculation:

Year ending Dec. 31,	Benchmark Price (Brent Blend) ($/bbl)	**Year ending Mar. 31,**	India Forecast Natural Gas Price ($/Mcf)	Bangladesh Forecast Natural Gas Price ($/Mcf)
2010	83.39	2011	3.97	2.33
2011	84.39	2012	3.95	2.33
2012	85.38	2013	3.91	2.33
2013	86.38	2014	3.88	2.33
2014	88.37	2015	5.52	2.33
Thereafter	97.85	Thereafter	6.74	2.33

10. ASSET RETIREMENT OBLIGATIONS

The asset retirement obligations relate to the future site restoration and abandonment costs including the costs of production equipment removal and environmental cleanup based on regulations and economic circumstances at March 31, 2010.

The following table reconciles the Company's asset retirement obligations as at March 31 of each fiscal year:

Years ended March 31,	**2010**	2009
Obligation, beginning of year	**$ 27,544**	$ 9,107
Obligations incurred	**864**	17,735
Revision in estimated cash flows	**153**	–
Accretion expense	**1,940**	717
Foreign currency translation	**19**	(15)
Obligation, end of year	**$ 30,520**	$ 27,544

Obligations that are incurred and settled within the fiscal period are not added to the asset retirement cost and obligation.

The Company has estimated the fair value of its total asset retirement obligations based on estimated future undiscounted liabilities of $72.3 million (March 31, 2009 – $73.8 million). The inflation rates used in calculating the fair value were 4.5 percent for Indian properties and 7 percent for Bangladeshi properties of the asset retirement obligations. The costs are expected to be incurred between 2011 and 2026. A credit-adjusted risk-free interest rate of 7.0 percent was used for obligations incurred up to

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December 31, 2009 and 5.0 percent thereafter was used in the fair value calculation to discount future costs.

In accordance with the Site Restoration Fund Scheme, 1999 in India, the Company is required to accumulate funds in a separate restricted account related to future asset retirement obligations. The funds may be used for site restoration on the expiry or termination of an agreement or relinquishment of part of the contract area. The fair value of assets that are legally restricted for purposes of settling asset retirement obligations is estimated at $5.0 million as at March 31, 2010 (March 31, 2009 – $3.5 million).

11. LONG-TERM DEBT

The Company has a facility agreement for $192.8 million. At March 31, 2010, the Company has drawn the full amount of the facility.

Interest was at LIBOR plus 1.7 percent during the year ended March 31, 2009. In April 2009, the facility was amended resulting in an interest rate on the debt of LIBOR plus 4.0 percent. During the year ended March 31, 2009, the Company capitalized interest of $8.3 million and commitment fees of $2.1 million. No amounts were capitalized with respect to the loan during the year ended March 31, 2010.

The Company is required to make repayments of the outstanding balance if the loan exceeds the amount specified in a reduction schedule or in order to bring financial coverage ratios within specified limits. Based on cashflow estimates using the current volume of gas contracts, the Company will be required to pay $155 million in fiscal 2011 in order to maintain the field life coverage ratio specified in the facility agreement. The facility will expire on September 30, 2011.

See further discussion of repayment in note 21. The facility is secured by a debt service reserve account and the assets of the D6 Block, Hazira Field, and Surat Block in India and Block 9 in Bangladesh.

12. CONVERTIBLE DEBENTURES

The Cdn$310 million, 5 percent senior secured convertible debentures (the “Debentures”) mature on December 30, 2012 with interest paid semi-annually in arrears on January 1st and July 1st of each year. Debentures are convertible at the option of the holder into common shares of the Company at a conversion price of Cdn$110.50 per common share until 60 days prior to the maturity date. After December 30, 2010, the Company may elect to convert all of the Debentures into common shares at the conversion price in effect on that date, provided that the weighted average trading price to the prior 21 trading days exceeds Cdn$143.65 per share.

The fair value of the conversion feature of the Debentures included in shareholders’ equity at the date of issue was $14.8 million. The debt component is accreted over the term of the obligation to the principal value on maturity with a corresponding charge to earnings. If the Debentures are converted to common shares, the corresponding amount of the conversion feature within shareholders’ equity will be reclassified to share capital along with the principal amount converted. At March 31, 2010, Debentures with a face value of Cdn$310 million (approximately US$305 million) remain outstanding.

13. SHARE CAPITAL

(a) AUTHORIZED

Unlimited number of common shares
Unlimited number of preferred shares

(b) ISSUED

Years ended March 31,	2010		2009	
	Number	**Amount**	Number	Amount
Common shares				
Balance, beginning of year	**49,298,133**	**$ 997,189**	49,054,408	$ 982,959
Shares issued for property acquisition (note 8)	**397,379**	**39,691**	–	–
Stock options exercised	**1,122,598**	**54,997**	243,725	11,615
Transferred from contributed surplus on exercise	**–**	**15,286**	–	2,615
Balance, end of year	**50,818,110**	**$ 1,107,163**	49,298,133	$ 997,189

(c) STOCK OPTIONS

The Company has reserved for issue 5,081,811 common shares for granting under stock options to directors, officers, and employees. The options become 100 percent vested one to four years after the date of grant and expire two to five years after the date of grant. Stock option transactions for the respective periods were as follows:

Years ended March 31,		2010		2009
	Number of Options	**Weighted Average Exercise Price (Cdn$)**	Number of Options	Weighted Average Exercise Price (Cdn$)
Outstanding, beginning of year	**4,030,750**	**64.69**	3,219,725	65.02
Granted	**1,530,312**	**92.18**	1,368,313	60.33
Forfeited	**(282,375)**	**90.25**	(18,250)	83.11
Expired	**(99,375)**	**92.72**	(295,313)	58.39
Exercised	**(1,122,598)**	**52.80**	(243,725)	50.85
Outstanding, end of year	**4,056,714**	**75.88**	4,030,750	64.69
Exercisable, end of year	**730,399**	**58.21**	1,132,562	54.02

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The following table summarizes stock options outstanding and exercisable under the plan at March 31, 2010:

	Outstanding Options			Exercisable Options	
Exercise Price	**Options**	**Remaining Life (Years)**	**Weighted Average Price (Cdn$)**	**Options**	**Weighted Average Price (Cdn$)**
$ 40.00 – $ 49.99	1,072,377	2.6	48.45	252,812	44.69
$ 50.00 – $ 59.99	296,687	0.9	53.69	280,312	53.70
$ 60.00 – $ 69.99	323,375	1.7	62.91	57,500	63.00
$ 70.00 – $ 79.99	76,250	3.1	76.05	11,250	79.69
$ 80.00 – $ 89.99	747,463	3.0	85.60	31,650	82.73
$ 90.00 – $ 99.99	1,223,250	2.7	95.45	96,625	93.20
$ 100.00 – $ 109.99	317,312	4.7	104.17	250	105.47
	4,056,714	2.7	75.88	730,399	58.21

Stock-based Compensation

The fair value of each option granted during the year was estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average grant-date fair values of options granted during the year ended March 31, 2010 were Cdn$32.94 (year ended March 31, 2009 – Cdn$22.67). The weighted average assumptions used in the Black-Scholes model to determine fair value for the current and prior years were as follows:

Black-Scholes Assumptions

Years ended March 31, (weighted average)	**2010**	2009
Risk-free interest rate	**2.3%**	2.8%
Volatility	**48%**	52%
Expected life (years)	**3.5**	3.5
Expected annual dividend per share (Cdn$)	**0.12**	0.12

14. CONTRIBUTED SURPLUS

Years ended March 31,	**2010**	2009 Restated (see note 2)
Contributed surplus, beginning of year	**$ 41,494**	$ 27,098
Stock-based compensation	**22,189**	17,011
Stock options exercised	**(15,286)**	(2,615)
Contributed surplus, end of year	**$ 48,397**	$ 41,494

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15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Years ended March 31,	2010	2009
Accumulated other comprehensive income (loss), beginning of year	**$ (2,406)**	$ 40,989
Other comprehensive income (loss):		
Foreign currency translation gain (loss)	**14,626**	(43,395)
Accumulated other comprehensive income (loss), end of year	**$ 12,220**	$ (2,406)

16. INTEREST AND FINANCING

Years ended March 31,	2010	2009
Interest expense related to capital lease	**$ 5,360**	$ 1,498
Interest expense on long-term debt	**9,599**	–
Interest expense on convertible debentures	**3,736**	–
Accretion expense on convertible debentures	**1,148**	–
Interest and financing expense	**$ 19,843**	$ 1,498

17. INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's income (loss) before income taxes. This difference results from the following items:

Years ended March 31,	2010	2009
Income (loss) before income taxes	**$ 123,229**	$ (13,808)
Statutory income tax rate	**28.75%**	29.38%
Computed expected income taxes (reduction)	**35,428**	(4,056)
Stock-based compensation expense	**5,695**	4,514
Income exempt from tax	**(35,261)**	(5,510)
Income tax adjustments	**–**	(164)
Adjustment to future Indian taxes	**(5,234)**	(9,936)
Foreign non-income related taxes	**34**	212
Difference between current and future income tax rates and other	**(4,778)**	4,455
Valuation allowance and other	**8,557**	15,544
Provision for income taxes	**$ 4,441**	$ 5,059

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The components of the Company's net future income tax liability at March 31 of each fiscal year are as follows:

Future income tax assets	2010	2009
Foreign currency cash and cash equivalents	$ –	$ –
Short-term investments	**2,040**	3,364
Long-term investments	**–**	743
Long-term account receivable	**728**	2,607
Property and equipment	**7,728**	4,594
Asset retirement obligations	**1,559**	1,490
Share issue expenses	**3,204**	4,951
Unused foreign tax credits	**28,872**	24,864
Minimum alternative tax credits	**20,410**	–
Unused losses	**13,443**	336
	$ 77,984	$ 42,949

Future income tax liabilities	2010	2009
Foreign currency cash and cash equivalents	**$ –**	$ 332
Property and equipment	**235,577**	1,040
Valuation allowance	**49,743**	41,577
	$ 285,320	$ 42,949
Net future income tax liability	**$ 207,336**	$ –

India's federal tax law contains a tax holiday deduction for seven years for profits from the commercial production of mineral oil. See discussion of application of the tax holiday provisions in contingency note 25 (e). As a result of the tax holiday provision in India, the Company pays the greater of 42.23 percent of taxable income in India after a deduction for the tax holiday or a minimum alternative tax of 19 percent of Indian income. Indian income is calculated in accordance with Indian generally accepted accounting principles.

The Company paid taxes for the Feni property in Bangladesh at a rate of 4.25 percent of revenues net of profit petroleum. In addition, the Company accrues taxes assessed by the Government of Bangladesh beyond the calculated taxes.

The Company does not pay income taxes related to the Block 9 production as indicated in the production sharing contract (PSC). The PSC indicates that the calculation for profit petroleum expense includes consideration of income taxes and, therefore, no income tax is assessed for Block 9.

The Company has $34.5 million of unused non-capital losses in Canada, which expire between 2014 and 2030 and $8.8 million for the Trinidad branch, which carryforward indefinitely. The Company has taken a valuation allowance on these losses and therefore has not recognized the benefit related to these losses.

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18. EARNINGS PER SHARE

The following table summarizes the weighted average number of common shares used in calculating basic and diluted earnings per share:

Years ended March 31,	**2010**	2009
Weighted average number of common shares outstanding		
– basic	**49,756,394**	49,202,400
– diluted	**50,124,307**	49,202,400

As the Company incurred a net loss for the year ended March 31, 2009, all 4,030,750 outstanding stock options were considered anti-dilutive and were therefore excluded from the calculation of diluted per share amounts. Options totaling 2,013,775 for the year ended March 31, 2010 were considered anti-dilutive as they were out-of-the money and were therefore excluded from the calculation of diluted per share amounts.

The convertible debentures were anti-dilutive for the year ended March 31, 2010 and have been excluded from the calculation of diluted earnings per share above. The convertible debentures were issued during the year ended March 31, 2010.

19. SEGMENTED INFORMATION

The Company's operations are conducted in one business sector, the oil and natural gas industry. 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 used in the preparation of the information of the reportable segments are the same as those described in the summary of significant accounting policies. Revenues, segment profits and capital additions by reportable segments are as follows:

Years ended March 31,		**2010**			2009	
Segment	**Revenue**	**Segment Profit (Loss)**	**Capital Additions**	Revenue	Segment Profit (Loss)	Capital Additions
Bangladesh	**$ 60,869**	**$ 8,204**	**$ 10,222**	$ 49,950	$ 7,847	$ 14,926
India	**272,633**	**146,539**	**141,554**	54,224	8,842	488,026
Indonesia	**–**	**–**	**521,062**	–	–	15,844
Kurdistan	**–**	**–**	**43,042**	–	–	24,077
Madagascar	**–**	**–**	**5,075**	–	–	4,393
Pakistan	**–**	**–**	**1,811**	–	–	22,770
Trinidad	**–**	**–**	**65,143**	–	–	–
All other[(1)]	**609**	**(2,077)**	**1,852**	819	(496)	1,432
Total	**$ 334,111**	**$ 152,666**	**$ 789,761**	$ 104,993	$16,193	$ 571,468

(1) Revenues included in All other are from Canadian oil sales.

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As at March 31,		**2010**		2009	
Segment		**Property, Plant and Equipment**	**Total Assets**	Property, Plant and Equipment	Total Assets
Bangladesh	**$**	**122,536**	**$ 159,433**	$ 138,468	$ 170,206
India		**1,013,691**	**1,147,703**	943,247	1,168,890
Indonesia		**537,233**	**562,071**	15,844	28,129
Kurdistan		**67,592**	**68,433**	24,344	28,242
Madagascar		**9,490**	**9,584**	4,393	5,826
Pakistan		**24,647**	**24,665**	22,770	22,839
Trinidad		**65,143**	**67,706**	–	–
All other		**4,494**	**206,859**	3,441	42,931
Total	**$**	**1,844,826**	**$ 2,246,454**	$1,152,507	$ 1,467,063

The reconciliation of the segment profit to net income (loss) as reported in the consolidated financial statements is as follows:

Years ended March 31, (thousands of U.S. dollars)		**2010**		2009
Segment profit	**$**	**152,666**	$	16,193
Interest and other income		**12,679**		11,824
Interest and financing expense		**(19,843)**		(1,498)
General and administrative expenses		**(11,069)**		(7,125)
Foreign exchange (loss) gain		**(10,154)**		8,104
Discount of long-term account receivable		**(176)**		(265)
Stock-based compensation expense		**(19,778)**		(15,294)
(Loss) gain on short-term investments		**14,554**		(24,380)
Loss on long-term investment		**(91)**		(982)
Impairment of long-term investment		**–**		(4,186)
Asset impairment		**–**		(1,258)
Net income (loss)	**$**	**118,788**	$	(18,867)

20. CAPITAL MANAGEMENT

Policy

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

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

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

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

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Capital Base

The Company's capital base includes shareholders' equity, outstanding long-term debt and convertible debentures:

Years ended March 31, (thousands of U.S. dollars)	**2010**	2009
Long-term debt	**$ 192,814**	$ 192,814
Convertible debentures	**$ 291,063**	$ –
Shareholders capital	**$ 1,107,163**	$ 997,189

The Company has certain obligations in accordance with its facility agreement and its convertible debenture agreement. The facility agreement defines levels within which the Company must maintain the ratio of debt to earnings before interest expense, taxes, depletion and any non-cash items. The convertible debenture agreement defines the levels within which the Company must maintain the ratios of debt to equity and earnings before interest expense, taxes, depletion and any non-cash items to interest expense. The Company monitors these ratios on a semi-annual basis in accordance with the agreements and is in compliance with the ratios as at March 31, 2010.

Capital Management

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

To manage capital, the Company uses a rolling five year projection. The projection provides details for the major components of sources and uses of cash for operations, financing and development and exploration expenditure commitments. Management and the Board of Directors review the projection annually and when contemplating interim financing or expenditure alternatives. The periodic reviews ensure that the Company has the short-term and long-term ability to fulfill its obligations, to fund ongoing operations, to pay dividends, to fund opportunities that might arise, to have sufficient funds to withstand financial difficulties or to bridge unexpected delays or satisfy contingencies and to grow the Company's producing assets.

21. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Company recognizes its short-term investment at fair value. The Company classifies fair value measurements using the following fair value hierarchy that reflects the significance of the inputs used in making the measurements:

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

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Short-term investments have been assessed on the fair value hierarchy described above and has been classified as Level 1. The fair value of the short-term investment was based on publicly quoted market values. Short-term investments have been recorded at their fair value of $32.1 million as at March 31, 2010. A gain of $14.6 million on recognizing the fair value of the investment at March 31, 2010 was recognized in income (March 31, 2009 – loss of $24.4 million).

Cash and cash equivalents and restricted cash are classified as held-for-trading and measured at fair value. Accounts receivable and long-term accounts receivable are classified as loans and receivables. The fair values of accounts receivable approximate their carrying value due to their short periods to maturity. A discount on the long-term account receivable of $0.2 million was recognized in income during the year ended March 31, 2010 (year ended March 31, 2009 –$0.3 million) resulting in the long-term account receivable being carried at approximately fair value.

Accounts payable and accrued liabilities, long-term debt and convertible debentures are classified as other financial liabilities that are not held for trading. The fair values of accounts payable and accrued liabilities approximate their carrying values due to their short periods to maturity. The Company's long-term debt bears interest based on a floating market rate and, accordingly, the fair market value approximates the carrying value. The carrying value of the Company's convertible debentures approximates the fair value.

Market Risk

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

(a) Currency Risk

The majority of the Company's revenues and expenses are denominated in U.S. dollars. In addition, the Company converts Canadian-held cash to U.S. dollars as required to fund forecast U.S. dollar expenditures. As a result, the Company has limited its cash exposure to fluctuations in the value of the U.S. dollar versus other currencies. However, the Company is exposed to changes in the value of the Indian rupee and Bangladesh taka versus the U.S. dollar as they are applied to the Company's working capital of its foreign subsidiaries. The Company's exposure to the changes in the value of the Bangladesh taka versus the U.S. dollar is not significant. The Company does not have any foreign exchange contracts in place to mitigate currency risk.

A 5 percent strengthening of the Indian rupee against the U.S. dollar at March 31, 2010, which is based on historical movements in the foreign exchange rates, would have decreased net income by $1.2 million. This analysis assumes that all other variables remained constant.

The financial instruments are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the cash and cash equivalents, accounts receivable, short-term investment and accounts payable of the Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar. A 6 percent weakening of the Canadian dollar against the U.S. dollar at March 31, 2010, which is based on historical movement in foreign exchange rates, would have increased net income by $11.5 million with an offsetting decrease to other comprehensive income. This analysis assumes that all other variables remained constant.

(b) Interest Rate Risk

The Company is exposed to interest rate risk on its money market funds and short-term deposits. The Company manages the interest rate risk on these investments by monitoring the interest rates on an ongoing basis. The Company is exposed to interest rate risk on its long-term debt and on interest income earned on cash and cash equivalents. If interest rates applicable to the long-term debt had been 40 basis points higher than they were during the period, which is based on historical changes in the applicable interest rates, net income would have decreased by $0.8 million. An opposite change in interest rates would result in an opposite change to net income.

(c) Commodity Price Risk

The Company is exposed to the risk of changes in market prices of commodities. The Company enters into natural gas contracts, which manages this risk. Because the Company has long-term fixed price gas contracts, a change in natural gas prices would not have impacted net income for the year ended March 31, 2010. The Company is exposed to changes in the market price of oil and condensate. In addition, the Company will be exposed to the change in the Brent crude price as the average Brent crude price from the preceding year is a variable in the gas price for the following year, calculated annually, for the D6 gas contracts.

(d) Other Price Risk

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

The Company is exposed to the risk of fluctuations in the market prices of its short-term investments. A 27 percent change in the publicly quoted market values at the reporting date, which is based on historical changes in market values, would have increased or decreased net income for the year by $8.7 million. The fair value was $32.1 million at March 31, 2010.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from customers. The carrying amounts of the cash and cash equivalents, restricted cash, accounts receivable and the long-term account receivable reflect management's assessment of the maximum credit exposure. The Company has accounts receivable from a larger number of customers than in the prior year as a result of the commencement of gas production in the D6 Block. There were no other changes in the Company's exposure to credit risks or any changes to the Company's processes for managing the risks from the previous period.

The accounts receivable balance includes $10.4 million and the long-term accounts receivable balances include $27.8 million receivable (discounted to $22.9 million) from one customer in Bangladesh.

The Company takes measures in order to mitigate any risk of loss, which may include obtaining guarantees. The specific industries or government may be affected by economic factors that may impact accounts receivable. The aging of accounts receivable as at March 31, 2010 was:

	As at March 31, 2010
0 – 30 days	**$ 32,270**
30 – 90 days	**13,615**
Greater than 90 days	**9,477**
Total accounts receivable	**$ 55,362**

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

The long-term account receivable balance consists of gas sales charged to Petrobangla for the production from the Feni field in Bangladesh. Payment of the receivable is being delayed as a result of various claims raised against the Company as described in note 25 (a) and (b). The long-term accounts receivable is comprised of $1.0 million that was recorded in fiscal 2010, $1.5 million that was recorded in fiscal 2009, and $25.3 million that was recorded prior thereto, and the combined receivable has been adjusted to approximate its fair value of $22.9 million. The long-term accounts receivable is not considered impaired. The Company considered the delay in payment, the writ and the lawsuit raised against the Company and progress towards resolving these issues in reaching the conclusion that the delay in payment is temporary. Despite the temporary delay in payment, the Company expects to collect the full amount of the receivable. The timing of collection is uncertain as the Company will not collect the receivable until resolution of the various claims raised against the Company described in note 25 (a) and (b).

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company manages this risk by preparing cashflow forecasts to assess whether additional funds are required. As at March 31, 2010, the Company had cash of $246.1 million (including restricted cash of $49.3 million) and financial liabilities as indicated below. The Company plans to settle its financial liabilities with cash on hand and cash flow from operations.

The Company has the following financial liabilities and due dates as at March 31, 2010:

	Carrying Value	**< 1 year**	**1 – 3 years**
Non-derivative financial liabilities(1)			
Accounts payable	123,546	123,546	–
Principal repayments on long-term debt	192,184	154,811	38,003
Repayment of convertible debentures(2) (see note 12)	291,063	–	291,063

(1) The Company also has capital lease commitments as outlined in note 24.

(2) The carrying value of the convertible debentures is the fair value of $291.1 million. The amount outstanding that will be required to be repaid assuming that the debentures are not converted is Cdn$310 million ($305.2 million as at March 31, 2010).

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22. GUARANTEES

As at March 31,		2010		2009
Performance security guarantees included in restricted cash(1)				
Cauvery - India	**$**	**804**	$	–
D4 - India		**984**(3)		–
Indonesia		**21,550**		12,285
Madagascar		**–**		1,178
Performance security guarantees not included in restricted cash(2)				
Cauvery - India		**–**		2,977
D4 - India		**–**		2,617
Indonesia		**2,454**		–
Block 9		**–**		5,334
Madagascar		**1,178**		–
Total Guarantees	**$**	**26,970**	$	24,391

(1) The Company is required to provide funds to support the guarantees in the amounts indicated above.
(2) These performance security guarantees are not reflected on the balance sheet as they are supported by Export Development Canada.
(3) Subsequent to March 31, 2010, the amount of the guarantee was increased to $3.2 million.

The Company has performance security guarantees related to the capital commitments for exploration blocks. See note 24 for details of the remaining minimum work commitments. The guarantees are cancelled when the Company completes the work required under the exploration period.

23. RELATED-PARTY TRANSACTIONS

The Company has a 45 percent interest in a Canadian property that is operated by a related party, a Company owned by the President and CEO of Niko Resources Ltd. This joint interest originated as a result of the related party buying the interest of the third-party operator of the property in 2002. The transactions with the related party are measured at the exchange amount, which is the amount agreed to between related parties.

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24. COMMITMENTS AND CONTRACTUAL OBLIGATIONS

(a) Exploration spending: The Company has commitments for approved annual budgets under various joint venture agreements. In addition, the Company has estimated the cost to complete the remaining work commitments as specified in the PSCs for its exploration blocks as follows:

Property	Estimated spending	Deadline for spending
India – D4 Block	$ 10,000	(2)
India – Cauvery Block	2,000	March 2011
Indonesia(1)	135,000	(3)
Kurdistan	12,000	May 2011
Madagascar	70,000	(4)
Trinidad – Central Range Block	17,000	September 2012
Trinidad – Block 2AB	28,000	July 2012
Trinidad – Guayaguayare Block	48,000	July 2013
Total	$ 322,000	

(1) Includes signing bonuses and work commitments for the Indonesian blocks acquired subsequent to March 31, 2010.

(2) Originally, the work commitment was to be completed by September 2009; however, the Government of India is in the process of approving a blanket extension of up to three years for this and other deepwater blocks, prompted by the shortage of deepwater drilling rigs. If the blanket extension is not approved, the Company will apply for a one year extension.

(3) The deadline for fulfilling the work commitments in Indonesia are: $71 million by November 2011; $23 million by May 2012; $11 million by November 2012; and $30 million by May 2013.

(4) The deadline for fulfilling the work commitments in Madagascar are: $30 million by September 2012 and $40 million by September 2015.

(b) Capital Lease: The Company has recognized the capital lease of the floating production, storage and off-loading vessel (FPSO) at the fair value of $63.8 million. The lease is for 9 years and has lease payments of $10.8 million per year. The discount rate used in determining the present value of minimum lease payments is 9 percent.

Fiscal 2011	$ 10,757
Fiscal 2012	10,757
Fiscal 2013	10,757
Fiscal 2014	10,757
Fiscal 2015	10,757
Thereafter (net of salvage value)	36,777
Total minimum payments	90,562
Less amount representing imputed interest	26,733
Present value of obligation under capital leases	$ 63,829

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25. CONTINGENCIES

(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 ($27.8 million as at March 31, 2010).	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. All bank accounts of the Company maintained in Bangladesh remain frozen 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.

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(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 356,392,000 ($5.3 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
(ii) taka 699,715,000 ($10.3 million) for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;
(iii) taka 845,560,000 ($12.5 million) for environmental damages, an amount subject to be increased upon further assessment;
(iv) taka 5,345,873,000 ($78.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and
(v) any other claims that arise from time to time.

ICSID has registered the request for arbitration of the issues indicated above as discussed in note 25(a). 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. Payments, if any, will be recorded in the period of determination.

(c) In accordance with natural gas sales contracts to customers in the vicinity of the Hazira field in India, the Company and its joint interest partner at Hazira have committed to certain minimum quantities. Should the Company fail to supply the minimum quantity of natural gas in any month as specified in the contract, the Company may be liable to pay the vendor an approximately equivalent amount. The Company was unable to deliver the minimum quantities up to December 31, 2007. The Company has agreed to provide five times the gas that the Company was unable to deliver from D6 volumes and receive the same price as for other D6 gas sold. In the event the Company is unable to deliver the volumes, the Company will have a potential liability, which is currently estimated at $10 million.

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

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

The Company has received unfavourable tax assessments related to taxation years 1999 through 2006. The assessments contend the 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. The 2007 and 2008 taxations years have not yet been assessed.

In India, there are potentially four levels of appeal related to tax assessments: Commissioner Income Tax - Appeals (“CIT-A”); the Income Tax Appellate tribunal (“ITAT”); the High Court; and the Supreme Court.

For taxation years 1999 to 2004, the Company has received favourable rulings at ITAT and the revenue Department has appealed to the High Court. For the 2005 taxation year, the Company has received a favourable ruling at CITA and for the 2006 taxation year, the Company’s CITA appeal is pending.

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 year ending March 31, 2009, 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 tax return, 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 record a tax expense of approximately $64 million, pay additional taxes of $41 million and write off approximately $23 million of the net income tax receivable. In addition, the Company could be obligated to pay interest on taxes for the past periods related to the periods assessed up to and including fiscal 2006.

(f) In January 2009, the Company received confirmation from Canadian authorities that they are engaged in a formal investigation into allegations of improper payments in Bangladesh by either the Company or its subsidiary in Bangladesh.

No charges have been laid against either the Company or its subsidiary in Bangladesh. The Company believes that the outcome of the investigation and associated costs, if any, to the Company are not determinable and no amounts have been recorded in these consolidated financial statements. Costs, if any, will be recorded in the period of determination.

(g) In December 2009, the arbitration of ownership of a 36-inch pipeline that is connected to the Hazira facilities in India was ruled in favor of the Company and its joint venture partner. The Government of India has filed a writ with the High Court in Delhi challenging the decision. The High Court has not yet ruled on whether they will hear the appeal. If the appeal is heard and the court rules against the Company and its joint venture partner, the Company will exclude the pipeline for cost recovery purposes in the calculation of profit petroleum and reverse the income and the capital asset recorded with respect to the pipeline. This would result in downward adjustments to net income of $13 million and to the capital asset of $5 million and to accounts receivable of $8 million.