NIKO RESOURCES LTD.

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED MARCH 31, 2008

JUNE 24, 2008

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ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	thousands of Canadian dollars	**"boe/d"**	barrels of oil equivalent per day
"MM$"	millions of Canadian dollars	**"Mbbl"**	thousand barrels
"bbl"	barrel	**"Mcf"**	thousand cubic feet
"bbls/d"	barrels per day	**"MMcf"**	million cubic feet
"bopd"	barrels of oil per day	**"Mcfe"**	thousand cubic feet of gas equivalent
"NGL"	natural gas liquids	**"Bcf"**	billion cubic feet
"boe"	barrels of oil equivalent	**"MMcf/d"**	million standard cubic feet per day
"Mboe"	thousand barrels of oil equivalent	**"MMbtu"**	million British thermal units

For the purposes of this document: (a) a barrel of oil equivalent is determined by converting (i) a volume of natural gas to barrels of oil using the ratio six thousand cubic feet of gas to one barrel of oil and (ii) a volume of NGL to barrels of oil using the ratio of one barrel of NGL to one barrel of oil; and (b) a thousand cubic feet of gas equivalent is determined by converting one barrel of oil to six thousand cubic feet of gas.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act*, S.A. 1981, c. B-15, together with any amendments thereto and all regulations promulgated thereunder;

"**BAPEX**" means the Bangladesh Petroleum Exploration Co.;

"**Block 9**" means the contract area Block 9 located in Bangladesh, onshore near the city of Dhaka, as identified in a PSC entered into by CIBL, Tullow Bangladesh Limited, Texaco Exploration Asia Pacific Regional Pathfinding Inc., Petrobangla and the Government of Bangladesh in April 2001;

"**Brent Blended**" means sweet type of crude oil that is used as a benchmark for the prices of other crude oils. It is a mix of crude oil from several facilities in the Ninian and Brent fields on the North Sea.

"**Cauvery Block**" means the contract area CY-ONN-2003/1 of Cauvery located onshore south India as identified in the PSC entered into by Niko and the GOI in September 2005;

"**Chattak**" means the contract areas of Chattak east and Chattak west located onshore Bangladesh on the northern Bangladesh/Indian border as identified in the JVA;

"**CIBL**" means Chevron International Bangladesh Limited;

"**Common Shares**" means the Common shares in the share capital of the Company;

"**D4 Block**" means the contract area Block MN-DWN-2003/1 located offshore east coast India in the Mahanadi Basin as identified in a PSC entered into by Niko, Reliance and the GOI in September 2005;

"**D6 Block**" means the contract area Block KG-DWN 98/3 located offshore east coast India as identified in a PSC entered into by Niko, Reliance and the GOI in April 2000;

"**Fang**" means the contract areas of Upper Fang Basin and Lower Fang Basin located onshore Thailand in the Mai Province as identified in the Petroleum Participation and Operation Agreement and Participation and Development of Abandoned Petroleum Production Wells Agreement entered into by the Ministry of Defence of Thailand and TIC in January 2006 and in the Farmout and Participation Agreement, a Heads of Agreement, an Operating

Agreement and an Area of Mutual Interest Agreement entered into by TIC and Niko Resources (Fang) Ltd., a wholly-owned subsidiary of the Company;

"**Feni**" means the contract area of Feni located in the Chittagong region of Bangladesh as identified in the JVA;

"**Fiscal 2006**" means the fiscal year of the Company ended March 31, 2006, "**Fiscal 2007**" means the fiscal year of the Corporation ended March 31, 2007, "**Fiscal 2008**" means the fiscal year of the Company ended March 31, 2008 and "**Fiscal 2009**" means the fiscal year of the Company ended March 31, 2009;

"**GBA**" means gas balancing agreement;

"**GOB**" means the Government of Bangladesh;

"**GOI**" means the Government of India;

"**GPSA**" means a gas purchase and sales agreement;

"**GSPC**" means Gujarat State Petroleum Corporation Limited;

"**GSPC JOA**" means the Joint Operating Agreement between the Company and GSPC signed on December 5, 1994, covering the operation of five fields in India being the Hazira, Bhandut, Cambay, Matar and Sabarmati fields located in Gujarat State in western India;

"**Hazira Field**" means the contract area known as the Hazira Field located onshore and offshore in Gujurat State, India as identified in a PSC entered into by Niko, GSPC and the GOI in September 2004;

"**JVA**" means the Joint Venture Agreement between the Company and BAPEX signed on October 16, 2003, covering the operation of three onshore fields in Bangladesh being the Feni, Chattak east and Chattak west fields located in the Dhaka and Chittagong areas of Bangladesh;

"**KRG**" means the Kurdistan Regional Government of Iraq;

"**LBDP**" means the Land Based Drilling Platform;

"**MI 52-110**" means the Canadian Securities Administrators' Multilateral Instrument 52-110 – Audit Committees;

"**NEC-25**" means the contract area Block NEC-OSN-97/2 located offshore east coast India as identified in a PSC entered into by Niko, Reliance and the GOI in April 2000;

"**Niko**" or the "**Company**" or the "**Corporation**" means Niko Resources Ltd. and its wholly owned subsidiaries;

"**NI 51-101**" means Canadian Securities Administrators' National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities;

"**Pakistan blocks**" means the contract areas Block No. 2465-3 (OFFSHORE INDUS-X), Block No. 2465-4 (OFFSHORE INDUS-Y), Block No. 2466-6 (OFFSHORE INDUS-Z) and Block No. 2466-7 (OFFSHORE INDUS NORTH), all located offshore in the Arabian Sea near the city of Karachi as identified in four PSAs entered into by Niko, the President of the Islamic Republic of Pakistan and Government Holdings (PVT.) Limited in March 2008;

"**Petrobangla**" means the Bangladesh Oil, Gas and Mineral Corporation;

"**PSA**" means production sharing agreement;

"**PSC**" means production sharing contract;

"**Qara Dagh Block**" means the contract area Block 10 located in Sulaymaniyah governorate of the Federal Region of Kurdistan in Iraq, as identified in a PSC entered into by Nikoresources (Kurdistan) Ltd., the Kurdistan Regional Government of Iraq in May 2008;

"**Reliance**" means Reliance Industries Limited;

"**Reliance JOA**" means the Joint Operating Agreements between the Company and Reliance Industries Limited signed on October 4, 2002 covering the operation of D6 Block and NEC-25 and signed April 4, 2007 covering the operation of the D4 Block;

"**Ryder Scott**" means Ryder Scott Company, independent oil and gas reservoir engineers of Calgary, Alberta;

"**Ryder Scott Report**" means the independent reserve and economic evaluation of Niko's oil and natural gas interests in the Hazira Field and the Surat Block, both located in Gujarat State, India, the D6 block, located offshore from the east coast India and Feni and Block 9, both located in Bangladesh prepared by Ryder Scott dated June 13, 2008 and effective March 31, 2008;

"**Surat Block**" means the contract area Block CBB-ONN-2000/2 located onshore in Gujarat State, India as identified in a PSC entered into by Niko and the GOI in July 2001; and

"**TSX**" means the Toronto Stock Exchange**.**

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements contained in this Annual Information Form, including estimates of reserves, estimates of future cash flow and estimates of future production as well as other statements about anticipated future events or results, are forward-looking statements. Forward-looking statements often, but not always, are identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect", "targeting" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions. The forward-looking statements that are contained in this Annual Information Form involve a number of risks and uncertainties. As a consequence, actual results might differ materially from results forecast or suggested in such forward-looking statements. Some of these risks and uncertainties are identified under the heading "Risk Factors" in this Annual Information Form. Additional information regarding such factors and other important factors that could cause results to differ materially may be referred to as part of particular forward-looking statements. The forward-looking statements are qualified in their entirety by reference to the important factors discussed under the heading "Risk Factors" herein and to those that may be discussed as part of particular forward-looking statements.

The information with respect to net present values of future net revenues from reserves presented throughout this Annual Information Form, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in the tables contained in this Annual Information Form are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

The estimates of reserves and future net revenue for individual properties contained herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Boe and Mcfe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl and a Mcfe conversion ratio of 1 bbl: 6 Mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead.

THE COMPANY

Niko Resources Ltd. was incorporated under the ABCA on March 27, 1987. On October 7, 1997, the Company's Articles of Incorporation were amended to delete the Company's class A shares and class B shares, to rename the Common Shares and to create a class of preferred shares. The Company's principal and registered office is located at Suite 4600, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

Niko Resources (Block 9) Limited is an indirect wholly-owned subsidiary of Niko Resources Ltd. with total revenues exceeding 10% of the consolidated revenues of Niko. Niko Resources (Block 9) Limited was incorporated and currently exists under the laws of Bermuda.

Niko (NECO) Limited is an indirect wholly-owned subsidiary of Niko Resources Ltd. with total assets exceeding 10% of the consolidated assets of Niko. Niko (NECO) Limited was incorporated and currently exists under the laws of Caymans.

BUSINESS OF THE COMPANY

General

Niko is engaged in the exploration for, and the development and production of, natural gas and oil in the countries of India, where it currently holds interest in three onshore and three offshore blocks, Bangladesh, where it currently holds interests in three onshore blocks, Pakistan, where it currently holds interests in four offshore blocks and Kurdistan, where it currently holds an interest in one onshore block. The Company also has minor interests in oil and gas properties in Canada. For further information on individual properties, see "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties".

As at March 31, 2008, Niko had approximately 17 employees at its head office in Calgary, Alberta, approximately 103 employees at its Indian offices and approximately 27 employees at its Bangladesh offices.

Three Year History

The following is a description of events and conditions that have influenced the general development of the business over the last three completed financial years:

In November 2007, the Company executed a facility agreement for its US$550 million credit facility. The facility is being used to fund 65% of the Company's share in the D6 natural gas development and, upon completion of the D6 natural gas development, may be used for other projects. The Company has drawn US$192.8 million on the loan and is currently prevented from drawing further amounts because the Company is unable to meet one of the conditions precedent to borrowing additional funds. The Company expects that this condition precedent will be fulfilled once the lenders have adopted projections based on the March 31, 2008 reserve reports and subsequently, the Company expects to be able to borrow additional funds.

In August 2007, the Company completed a prospectus offering of 4,762,000 Common Shares at a price of $105.00 per Common Share for net proceeds of $480,900,600 after deducting underwriting fees of $20,000,400.

Development plans for the NEC-25 Block for the six discoveries that have been declared commercial by the Indian regulatory authorities have been prepared, were approved by the Joint Venture's Operating Committee in May of 2007 and subsequently submitted to the GOI. Once approved, estimated development costs and more information with respect to timing will be available.

In February 2007, the Company completed a prospectus offering of 2,300,000 Common Shares at a price of $81.50 per Common Share for net proceeds of $179,952,000 after deducting underwriting fees of $7,498,000.

In December 2006, the addendum to the initial development plant for the Dhirubhai-1 and 3 gas discovered in the D6 block was approved by the GOI. The development of the discoveries is now substantially complete. Natural gas production is expected to commence in the third calendar quarter of 2008.

In August 2006, the Company completed a prospectus offering of 2,000,000 Common Shares at a price of $63.25 per Common Share for net proceeds of $121,440,000 after deducting underwriting fees of $5,060,000.

Natural gas production from the Block 9 field in Bangladesh commenced in May 2006 and commerciality was declared in December 2006.

During Fiscal 2006, the Company entered into a purchase and sale agreement for the sale of its interests in the Bhandut, Cambay and Sabarmati oil fields located onshore India. The aggregate sale price for these fields was US$5.5 million. The completion of the sale was subject to approval from the GOI and was finalized in Fiscal 2007.

In March of 2006, the Company, through a subsidiary, commenced operations in northern Thailand through the acquisition of a 50% interest in certain aspects of the 343 square kilometre Fang block in the Fang basin. The Company drilled three unsuccessful exploration wells, performed seven unsuccessful workovers and drilled one successful well. During Fiscal 2008, the Company exited Thailand.

In September of 2005, the Company signed a PSC with the GOI for the onshore Cauvery Block in southeast India in the state of Tamil Nadu. Niko has a 100% interest in this block which covers 957 square kilometres. See "Statement of Reserves Data – Oil and Gas Properties – India – Terms of the Indian PSCs" for a description of the terms of the PSC.

In September of 2005, the Company signed a PSC with the GOI and Reliance for the offshore D4 Block. Niko has a 15% interest in the D4 Block and Reliance holds the remaining 85%. Reliance is the operator of the D4 Block. The D4 Block covers 17,000 square kilometres off the east coast of India. See "Statement of Reserves Data – Oil and Gas Properties – India – Terms of Indian PSCs" for a description of the terms of the PSC.

In June 2005, a second uncontrolled flow of natural gas occurred while drilling a relief well to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 location in January of 2005. The Company proceeded to construct a second relief well location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored. The Company's capital activities with respect to both the Chattak and Feni fields have been postponed pending overdue payment for gas owed to the Company by the Government of Bangladesh. During Fiscal 2006, a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh against various parties including Niko Resources (Bangladesh) Ltd. ("**NRBL**"), a subsidiary of Niko Resources Ltd. During Fiscal 2006, NRBL received a letter from the Government of Bangladesh making a number of demands as compensation for the uncontrolled flow problems that occurred in the Chattak field in January and June 2005. In June of 2008, a lawsuit commenced against NRBL by the GOB and Petrobangla seeking damages in the amount of 746.50 Crore Taka, together with interest at 12% per annum, until satisfaction of any judgement. For additional details on the writ and the lawsuit against NRBL and the demand for compensation, see "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields, Bangladesh".

Recent Developments

In May 2008, the Company entered into a PSC with the Kurdistan Regional Government of Iraq for an interest in an onshore block in Sulaymaniyah governorate of the Federal Region of Kurdistan in Iraq. See "Statement of Reserves Data – Oil and Gas Properties – Kurdistan – Terms of the Kurdistan PSC" for a description of the terms of the PSC.

In April 2008, development plans for the Cretaceous oil discovery (MA) in the D6 Block were approved by the GOI. The development and fast-track implementation of the Cretaceous oil discovery (MA) is now substantially complete. Oil production is expected to commence in the third calendar quarter of 2008.

In March 2008, the Company signed PSAs with the President of the Islamic Republic of Pakistan and Government Holdings (PVT) Limited for four offshore blocks in the Arabian Sea near the City of Karachi. Niko has a 100% interest in these blocks which cover approximately 10,000 square kilometres. See "Statement of Reserves Data – Oil and Gas Properties – Pakistan – Terms of the Pakistani PSAs" for a description of the terms of the PSAs.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "**Statement**") is dated June 24, 2008 and is effective March 31, 2008. The preparation date of the information regarding reserves in the Statement was June 13, 2008.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues presented in the tables below are representative of the fair market value of the reserves. There is no assurance that the price and cost assumptions will be attained and variances could be material.

Disclosure of Reserves Data

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and natural gas liquids and the net present values of future net revenues associated with the Company's reserves as evaluated in the Ryder Scott Report, based on forecast price assumptions presented in accordance with NI 51-101.

There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Company's material properties, reserves and production are located in India and Bangladesh. The Company also has properties in Canada. Reserves attributable to the Company's Canadian properties constitute less than 0.1% of the Company's total reserves and therefore have not been evaluated and are not included in the reserve information provided below.

Reserves Disclosure – Total India and Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for both its India and Bangladesh properties as a whole, as at March 31, 2008, from the Ryder Scott Report, using forecast prices and costs as well as the aggregate net present value of future net revenue attributable to the reserves (both before and after future income tax expenses) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India and Bangladesh
Forecast Price and Costs
As at March 31, 2008

Reserves Category	Light and Medium Crude Oil Gross (Mbbl)	Light and Medium Crude Oil Net[1] (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net[1] (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net[1] (Mbbl)
PROVED						
Developed Producing	73	58	119,936	81,780	123	81
Developed Non-Producing	14	11	62,842	28,318	73	33
Undeveloped	2,900	2,810	997,540	633,285	3,979	2,009
TOTAL PROVED	2,986	2,880	1,180,319	743,383	4,174	2,123
PROBABLE	1,285	1,191	502,282	301,113	457	661
TOTAL PROVED PLUS PROBABLE	4,271	4,071	1,682,601	1,044,495	4,632	2,784

Net Present Values of Future Net Revenues – India and Bangladesh[2]
Forecast Prices and Costs
As at March 31, 2008

	Before Income Taxes Discounted at (%/year)					
Reserves Category	0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)	Unit Value Before Income Tax Discounted at 10%/year
PROVED						($/Mcfe)
Developed Producing	168,423	146,637	129,463	115,660	104,375	1.57
Developed Non-Producing	46,321	34,993	27,490	22,139	18,080	0.96
Undeveloped	1,941,010	1,587,899	1,311,492	1,093,000	918,520	1.98
TOTAL PROVED	2,155,754	1,769,529	1,468,444	1,230,799	1,040,976	1.90
PROBABLE	928,128	604,855	399,292	267,302	181,642	1.28
TOTAL PROVED PLUS PROBABLE	3,083,882	2,374,384	1,867,736	1,498,101	1,222,618	1.72

Net Present Values of Future Net Revenues – India and Bangladesh[2]
Forecast Prices and Costs
As at March 31, 2008

Reserves Category	After Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	164,623	142,974	125,928	112,246	101,074
Developed Non-Producing	46,284	34,958	27,458	22,110	18,053
Undeveloped	1,744,015	1,424,205	1,172,297	972,677	813,229
TOTAL PROVED	1,954,922	1,602,137	1,325,683	1,107,033	932,357
PROBABLE	736,956	478,952	313,674	207,192	138,110
TOTAL PROVED PLUS PROBABLE	2,691,878	2,081,089	1,639,357	1,314,225	1,070,467

Notes:

(1) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that will be payable to the Governments of India and Bangladesh.

(2) These values reflect reductions for the estimates for profit petroleum amounts that will be payable to the Governments of India and Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for both its India and Bangladesh properties as a whole derived from the Ryder Scott Report estimated using forecast prices and costs and calculated without discount:

Future Net Revenue
India and Bangladesh Properties
As at March 31, 2008

($ Thousands)	Forecast Prices and Costs (Undiscounted) Proved Reserves	Proved Plus Probable Reserves
Revenue[1]	5,535,378	8,311,327
Profit Petroleum[2]	(2,226,318)	(3,379,243)
Royalties	(345,149)	(589,363)
Operating Costs	(282,981)	(346,549)
	2,680,930	3,996,172
Development Costs	(477,306)	(863,898)
Abandonment and reclamation costs	(47,870)	(48,391)
Future Net Revenue before deducting Future Income Taxes	2,155,754	3,083,882
Future Income Taxes	(200,832)	(392,004)
Future net revenue after deducting income taxes	1,954,922	2,691,878

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production for the Hazira and Surat properties in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Revenue as presented above is the contracted price plus the amount of royalties levied by the GOI.

(2) Under the terms of the applicable Indian PSCs and JVA, the governments of India and Bangladesh are entitled to a percentage share of the profit oil and gas produced from the Company's Indian properties and Feni property in Bangladesh, which percentage

is based upon the multiple of investment cost recovered by the Company. Under the terms of the Bangladesh PSC for Block 9, the Government of Bangladesh is entitled to a percentage share of the profit oil and gas produced from Block 9, which percentage is based upon the production levels and whether or not the Company has recovered its investment in the field. See "Statement of Reserves Data and Other Oil and Gas Information - Oil and Gas Properties – India – Terms of Indian PSCs" and "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh".

The following tables detail by production group and on a unit value basis for each production group, the net present value of future net revenue (before deducting future income tax expenses) for India and Bangladesh derived from the Ryder Scott Report, estimated using forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue – India and Bangladesh
By Production Group
As at March 31, 2008
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value
India and Bangladesh			
Proved	Light and Medium Oil[1]	72,116	$12.49/bbl
	Natural Gas[2]	1,396,328	$1.89/Mcfe
		1,468,444	
Total Proved plus Probable	Light and Medium Oil[1]	179,383	$19.58/bbl
	Natural Gas[2]	1,688,352	$1.64/Mcfe
		1,867,736	

Notes:

(1) Light and medium oil includes solution gas and other by-products.

(2) Natural Gas includes by-products such as natural gas liquids but excludes solution gas from oil wells.

Reserves Disclosure – India

The following tables detail the aggregate gross and net reserves of the Company for its India properties as a whole, as at March 31, 2008, derived from the Ryder Scott Report, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves (both before and after future income tax expense) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – India
Forecast Price and Costs
As at March 31, 2008

Reserves Category	Light and Medium Crude Oil Gross (Mbbl)	Light and Medium Crude Oil Net[1] (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net[1] (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net[1] (Mbbl)
PROVED						
Developed Producing	73	58	14,017	12,065	-	-
Developed Non-Producing	14	11	20	17	-	-
Undeveloped	2,900	2,810	997,540	633,285	3,979	2,009
TOTAL PROVED	2,986	2,880	1,011,576	645,366	3,979	2,009
PROBABLE	1,285	1,191	393,531	257,270	332	610
TOTAL PROVED PLUS PROBABLE	4,271	4,071	1,405,108	902,636	4,310	2,619

Net Present Values of Future Net Revenues – India[2]
Forecast Prices and Costs
As at March 31, 2008

Reserves Category	Before Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)	Unit Value Before Income Taxes Discounted at 10%/year ($/Mcfe)
PROVED						
Developed Producing	35,847	34,780	33,722	32,682	31,668	2.72
Developed Non-Producing	588	535	487	443	403	5.76
Undeveloped	1,941,010	1,587,899	1,311,492	1,093,000	918,520	1.98
TOTAL PROVED	1,977,445	1,623,214	1,345,700	1,126,125	950,592	1.99
PROBABLE	846,696	547,908	358,562	237,623	159,694	1.34
TOTAL PROVED PLUS PROBABLE	2,824,141	2,171,122	1,704,262	1,363,748	1,110,286	1.81

Net Present Values of Future Net Revenues – India[2]
Forecast Prices and Costs
As at March 31, 2008

Reserves Category	After Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	32,117	31,185	30,254	29,333	28,431
Developed Non-Producing	551	501	455	414	376
Undeveloped	1,744,015	1,424,205	1,172,297	972,677	813,229
TOTAL PROVED	1,776,683	1,455,891	1,203,006	1,002,424	842,037
PROBABLE	655,679	422,145	273,070	177,625	116,263
TOTAL PROVED PLUS PROBABLE	2,432,362	1,878,035	1,476,075	1,180,049	958,300

Notes:

(1) "Net" reserves are defined as those accruing to Niko's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that will be payable to the GOI.

(2) These values reflect reductions for the estimates for profit petroleum amounts that will be payable to the GOI.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its India properties derived from the Ryder Scott Report estimated using forecast prices and costs and calculated without discount:

Future Net Revenue
Total India Properties
As at March 31, 2008

($ Thousands)	Forecast Prices and Costs (Undiscounted) Proved Reserves	Proved Plus Probable Reserves
Revenue[1]	5,123,637	7,635,807
Profit Petroleum[2]	(2,053,681)	(3,048,545)
Royalty	(345,149)	(589,363)
Operating Costs	(243,943)	(296,844)
	2,480,864	3,701,055
Development costs	(455,831)	(828,884)
Abandonment and reclamation costs	(47,588)	(48,031)
Future Net Revenue before deducting Future Income Taxes	1,977,445	2,824,141
Future Income Taxes	(200,762)	(391,779)
Future net revenue after deducting Future Income Taxes	1,776,683	2,432,362

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production in India, the purchasers of natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Revenue as presented above is the contracted price plus the amount of royalties levied by the GOI.

(2) Under the terms of the applicable Indian PSCs, the GOI is entitled to a percentage share of the profit gas produced from the Company's Indian properties, which percentage is based upon the multiple of investment cost recovered by the Company. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Terms of Indian PSCs".

The following table details by production group and on a unit value basis for each production group, the net present value of future net revenue (before deducting future income tax expenses) for India derived from the Ryder Scott Report, estimated using forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue –India
By Production Group
As at March 31, 2008
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value
Proved	Light and Medium Oil (bbls)[1]	72,116	$12.49/bbl
	Natural Gas (Mcfe)[2]	1,273,584	$1.99/Mcfe
		1,345,700	
Total Proved plus Probable	Light and Medium Oil (bbls)[1]	179,383	$19.58/bbl
	Natural Gas (Mcfe)[2]	1,524,879	$1.72/Mcfe
		1,704,262	

Notes:

(1) Light and medium oil includes solution gas and other by-products.

(2) Natural Gas includes by-products such as natural gas liquids but excludes solution gas from oil wells.

Reserves Disclosure - Bangladesh

The following tables detail the aggregate gross and net reserves of the Company for its Bangladesh properties as a whole, as at March 31, 2008, derived from the Ryder Scott Report, using forecast prices and costs as well as the aggregate net present value of future net revenue attributable to the reserves (both before and after income taxes) estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves – Bangladesh[1]
Forecast Price and Costs
As at March 31, 2008

	Light and Medium Crude Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (Mbbl)	Net[2] (Mbbl)	Gross (MMcf)	Net[2] (MMcf)	Gross (Mbbl)	Net[2] (Mbbl)
PROVED						
Developed Producing	-	-	105,920	69,715	123	81
Developed Non-Producing	-	-	62,823	28,301	73	33
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	-	-	168,743	98,016	196	114
PROBABLE	-	-	108,751	43,842	126	51
TOTAL PROVED PLUS PROBABLE	-	-	277,493	141,859	322	164

Net Present Values of Future Net Revenues – Bangladesh(1)(3)
Forecast Prices and Costs
As at March 31, 2008

Reserves Category	Before Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)	Unit Value Before Income taxes Discounted at 10%/year
PROVED						($/Mcfe)
Developed Producing	132,576	111,857	95,741	82,978	72,707	1.36
Developed Non-Producing	45,733	34,458	27,003	21,696	17,677	0.95
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	178,309	146,315	122,744	104,674	90,384	1.24
PROBABLE	81,432	56,946	40,730	29,680	21,948	0.92
TOTAL PROVED PLUS PROBABLE	259,741	203,261	163,474	134,354	112,332	1.14

Net Present Values of Future Net Revenues –Bangladesh(1)(3)
Forecast Prices and Costs
As at March 31, 2008

Reserves Category	After Income Taxes Discounted at (%/year) 0% ($ thousands)	5% ($ thousands)	10% ($ thousands)	15% ($ thousands)	20% ($ thousands)
PROVED					
Developed Producing	132,506	111,789	95,675	82,913	72,643
Developed Non-Producing	45,733	34,458	27,003	21,696	17,677
Undeveloped	-	-	-	-	-
TOTAL PROVED	178,239	146,247	122,677	104,609	90,320
PROBABLE	81,277	56,808	40,605	29,567	21,847
TOTAL PROVED PLUS PROBABLE	259,517	203,054	163,282	134,176	112,167

Notes:

(1) The above tables present the reserve numbers and net present value of future net revenue attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that will be payable to the Government of Bangladesh.

(3) These values reflect reductions for the estimates for profit petroleum amounts that will be payable to the Government of Bangladesh.

The following table provides a breakdown of the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for its Bangladesh properties derived from the Ryder Scott Report estimated using forecast prices and costs and calculated without discount:

($ Thousands)	Future Net Revenue Total Bangladesh Properties As at March 31, 2008 Forecast Prices and Costs (Undiscounted) Proved Reserves	 Proved Plus Probable Reserves
Revenue	411,741	675,520
Profit Petroleum[(1)]	(172,636)	(330,699)
Operating Costs	(39,038)	(49,706)
	200,067	295,115
Development Costs	(21,475)	(35,014)
Abandonment and reclamation costs	(282)	(360)
Future Net Revenue before deducting Future Income Taxes	178,309	259,741
Future Income Taxes	(70)	(225)
Future net revenue after deducting Future Income Taxes	178,239	259,517

Note:

(1) Under the terms of the JVA for Feni, the Government of Bangladesh is entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovered by the Company. Under the terms of the PSC for Block 9, the Government of Bangladesh is entitled to a percentage share of the profit gas produced, which percentage is based upon the production level and whether or not the Company has recovered its investment in the field. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh". The Ryder Scott Report, which evaluates the Company's interest in the Feni field and Block 9 in Bangladesh, presents revenue gross of profit petroleum. The profit petroleum deducted in the table above relates to profit petroleum on the Feni field and Block 9.

The following table details by production group the net present value of future net revenue (before deducting future income tax expenses) for Bangladesh derived from the Ryder Scott Report, estimated using forecast prices and costs and calculated using a discount rate of 10%.

Future Net Revenue – Bangladesh
By Production Group
As at March 31, 2008
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value
Proved	Natural Gas (Mcfe) [(1)]	122,744	$1.24/Mcfe
		122,744	
Total Proved plus Probable	Natural Gas (Mcfe) [(1)]	163,474	$1.14/Mcfe
		163,474	

Note:

(1) Natural Gas includes by-products such as natural gas liquids but excludes solution gas from oil wells.

Pricing Assumptions

Ryder Scott Report

The following tables detail the reference prices as of March 31, 2008 utilized by Ryder Scott in the Ryder Scott Report for evaluating the net present values of future net revenues from reserves in the Hazira Field, the Surat Block and the D6 Block in India and the Feni field and Block 9 in Bangladesh disclosed above under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data". Ryder Scott is an independent qualified reserves evaluator and auditor.

Summary of Pricing and Inflation Rate Assumptions
As of March 31, 2008
Forecast Prices and Costs(1)
For Hazira Field, Surat Block and D6 Block

	Hazira – Oil	Hazira – Oil	Hazira – Natural Gas	Surat – Natural Gas	D6 - Oil	D6 - Oil
Year	Proved ($US/bbl)(2)	Proved Plus Probable ($US/bbl)(2)	($US/ Mcf)	($US/ Mcf)	Proved ($US/bbl)(2)	Proved Plus Probable ($US/bbl)(2)
Forecast						
2009	89.08	88.72	4.58	5.13	87.69	87.76
2010	83.29	83.16	4.97	5.64	83.16	82.97
2011	78.83	78.16	4.84	5.69	78.15	78.06
2012	74.61	74.68	4.84	5.69	74.86	74.74
2013	73.21	73.21	4.84	5.69	73.21	73.21
Average thereafter	80.18	80.18	4.89	5.69	80.18	80.18

	D6 - Condensate	D6 – Condensate	D6 – D1&D3 Gas	D6 – MA Associated Gas		
Year	Proved ($US/bbl)(2)	Proved Plus Probable ($US/bbl)(2)	($US/ Mcf)	($US/ Mcf)	Inflation Rate(3)	Exchange Rate
2009	88.67	88.67	3.82	4.19	4.0	1.0
2010	82.35	82.22	3.82	4.19	4.0	1.0
2011	77.85	77.78	3.82	4.19	3.5	1.0
2012	74.81	74.67	3.82	4.19	2.0	1.0
2013	73.21	73.21	3.82	4.19	2.0	1.0
Average thereafter	80.17	80.16	6.26	6.87	2.0	1.0

Notes:

(1) The natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott. The oil and NGL prices shown on this table were provided by Ryder Scott and reflect its current estimates, which are based on its survey of future hydrocarbon parameters used by financial institutions and others in industry. The estimated natural gas prices are the negotiated prices plus royalty expense, which are assumed to be paid by the purchaser.

(2) The reference price used by Ryder Scott is Brent Blended.

(3) The forecast inflation rate provided by Ryder Scott is as shown above, however, this does not apply to natural gas prices contracted and estimated for the Hazira field, the Surat Block or the D6 Block.

Summary of Pricing and Inflation Rate Assumptions
As of March 31, 2008
Forecast Prices and Costs(1)
for Feni Field and Block 9

Year	Feni – Condensate ($US/bbl)	Feni – Natural Gas ($US/Mcf)	Block 9 – Condensate Proved ($US/bbl)	Block 9 – Condensate Proved Plus Probable ($US/bbl)	Block 9 – Natural Gas ($US/Mcf)	Inflation Rate %/Year(2)	Exchange Rate ($US/$CAD)
Forecast							
2009	40.00	1.75	103.46	103.46	2.34	4.0	1.0
2010	40.00	1.75	96.82	96.78	2.34	4.0	1.0
2011	40.00	1.75	90.89	90.89	2.34	3.5	1.0
2012	40.00	1.75	87.09	87.05	2.34	2.0	1.0
2013	40.00	1.75	85.41	85.41	2.34	2.0	1.0
Average thereafter	40.00	1.75	93.53	93.51	2.34	2.0	1.0

Notes:

(1) The condensate and the natural gas prices shown on the table were provided by Ryder Scott based on discussions with Niko, contractual agreements and sales data provided by Niko to Ryder Scott.

(2) The forecast inflation rate provided by Ryder Scott is shown above, however, this does not apply to the contracted natural gas prices for Feni or Block 9 or the condensate price for Feni.

The Company's weighted average prices received in India prior to a reduction for any profit petroleum amounts payable to the GOI in Fiscal 2008 were US$77.96 per bbl for oil, US$54.92 for natural gas liquids and US$4.35 per Mcf for natural gas. Weighted average condensate and natural gas prices received by the Company in Bangladesh prior to a reduction for any profit petroleum amounts payable to the Government of Bangladesh in Fiscal 2008 were US$81.90 per bbl for natural gas liquids and US$2.27 per Mcf for natural gas, respectively. The average $US/$CAD exchange rate applicable to Fiscal 2008 was 1.0319.

There was no production from the D6 Block in Fiscal 2008.

Reconciliations of Changes in Reserves

The following table outlines the reconciliation of changes in the gross reserves estimates for the Company's Indian properties as at March 31, 2007 and as at March 31, 2008, using forecast prices and costs.

Reconciliation of Company Gross Reserves by Production Group – India
Forecast Prices and Costs

	Light and Medium Oil			Associated and Non-Associated Gas		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)
March 31, 2007	114	157	271	466,140	699,370	1,165,510
Extensions	-	-	-	477,057	(310,997)	166,060
Technical Revisions	53	(31)	22	94	(1,416)	(1,322)
Discoveries	2,900	1,160	4,060	79,701	6,575	86,276
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(81)	-	(81)	(11,416)	-	(11,416)
March 31, 2008	2,986	1,285	4,271	1,011,576	393,531	1,405,108

The following table outlines the reconciliation of changes in the gross reserves estimates for the Company's Bangladesh properties, as at March 31, 2007 and March 31, 2008, derived from the reports of Ryder Scott using forecast prices and costs.

Reconciliation of Company Gross Reserves by Production Group – Bangladesh[(1)]
Forecast Prices and Costs

	Associated and Non-Associated Gas		
Factors	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)
March 31, 2007	188,934	110,805	299,739
Extensions & Improved Recovery	-	-	-
Technical Revisions	(1,956)	(2,054)	(4,010)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(18,236)	-	(18,236)
March 31, 2008	168,743	108,751	277,493

Notes:

(1) The above tables present the reserve numbers attributable to those reserves contained in the Ryder Scott Report for the Company's Bangladesh properties. The Ryder Scott Report evaluates the Company's interest in the Feni field and Block 9 in Bangladesh.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table outlines the volumes of proved and probable undeveloped reserves included in the Company's reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time:

Undeveloped Reserves First Attributed
Forecast Prices and Costs

	Light and Medium Oil	Natural Gas	Natural Gas Liquids
	Gross (Mbbl)	Gross (MMcf)	Gross (Mbbl)
PROVED UNDEVELOPED			
2008	2,900	555,960	3,979
2007	-	3,080	-
2006	-	199,437	-
Prior thereto	211	365,007	-
PROBABLE UNDEVELOPED			
2008	1,160	-	332
2007	-	93,321	104
2006	-	1,130,000	-
Prior thereto	60	507,335	-

The proved and probable undeveloped reserves of the Company have been estimated in accordance with procedures and standards contained in the COGE Handbook. The Company has proved and probable undeveloped natural gas reserves for the D6 Block in India and probable undeveloped natural gas and natural gas liquid reserves for Block 9 in Bangladesh. The undeveloped reserves in these blocks are expected to be fully developed within the next two years. See "Oil and Gas Properties – India – D6 Block, India" and "Oil and Gas Properties – Bangladesh – Block 9, Bangladesh" for a description of the plan and timing for development. The reserves attributable to the Feni field in Bangladesh and to the Hazira and Surat fields in India are fully developed.

The Company's undeveloped properties, including the NEC-25, Cauvery and D4 Blocks in India Chattak East and Chattak West in Bangladesh, the four blocks in Pakistan and the block in Kurdistan do not have reserves, as defined in NI 51-101, attributable to them.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see the Company's management's discussion and analysis of financial condition, results of operations and cash flows for Fiscal 2008 and "Risk Factors" herein.

Future Development Costs

The following tables detail the development costs deducted in the estimation of future net revenue of the Company for its India properties derived from the Ryder Scott Report and for its Bangladesh properties as derived from the Ryder Scott Report attributable to proved reserves and proved plus probable reserves (both estimated using forecast prices and costs):

Future Development Costs – India[1]
($ thousands)

Year	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2009	298,429	298,429
2010	44,876	45,102
2011	89,584	84,547
2012	24,550	24,669
2013	1,863	340,444
Remainder	44,116	83,724
Total Undiscounted	503,418	876,915

Note:

(1) Includes amounts related to the future development and abandonment and reclamation costs.

Future Development Costs – Bangladesh[1]
($ thousands)

Year	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2009	18,957	18,957
2010	1,202	14,626
2011	-	-
2012	-	122
2013	28	-
Remainder	1,570	1,669
Total Undiscounted	21,757	35,374

Note:

(1) Includes amounts related to the future development and abandonment and reclamation costs.

The Company's source of funding for future development costs of the Company's reserves is expected to be derived from a combination of current cash balances, cash flow and debt. Management of the Company does not anticipate that the costs of funding referred to above will materially affect the Company's disclosed reserves and future net revenues or will make the development of any of the Company's properties uneconomic.

Oil and Gas Properties

The following is a description of Niko's principal oil and natural gas properties. Information in respect of gross and net acres, well counts and production information are as at March 31, 2008 unless otherwise indicated.

India

The Company has an interest in one oil and natural gas field (Hazira) and one natural gas block (Surat) that are producing in India. Production is sold to various industrial users and natural gas is distributed via owned and non-owned pipelines and oil is trucked to the customer. During Fiscal 2008, three customers purchasing production from India accounted for approximately 34%, 23% and 11% of revenues generated in India and 17%, 11% and 6% of consolidated revenues. During Fiscal 2007, three customers purchasing production from India accounted for approximately 37%, 18% and 14% of revenues generated in India and 22%, 11% and 8% of consolidated revenues. Markets, distribution methods, significant gas sales contracts and changes to contracts for individual properties are discussed in this section under “Hazira, India” and “Surat, India”. There are also two offshore gas blocks, one offshore oil and gas block and one onshore oil block in India that are not fully developed. See discussion in this section under "D6 Block, India", "NEC-25, India", "Cauvery, India" and "D4 Block, India".

(a) Hazira, India

In September 1994, Niko, GSPC and the GOI executed a PSC for the Hazira Field in India. Niko is the operator of the field and holds a 33.33% interest therein. The field is located close to several large industries about 25 kilometres southwest of the city of Surat and covers an area of approximately 50 square kilometres.

Much of the Hazira Field lies offshore in the shallow waters of the Arabian Sea. Phase I development of the field included the construction of a land based drilling platform (LBDP) and installation of a gas plant, which were completed by February 1999. The LBDP consists of a 1.5 kilometre causeway extending into the Gulf of Cambay with a 10,000 square-meter island at the end. Seventeen wells on the island are tied-in and on production. Two offshore appraisal wells drilled in March 2001 and March 2002 provided additional information on the field's reserves, as did a 3D seismic program shot in May and June 2001. A twin gas plant was installed in the year ended March 31, 2002. Phase II development of the field included construction of an offshore platform, which was completed and installed in April 2004. Nine gas wells and one oil well are producing from the offshore platform. The plant was expanded in the year ended March 31, 2005 by adding a dew point control unit as well as compression equipment.

The Company has the right under all of its Indian PSCs to freely market the natural gas it produces. Gujarat State is one of the most industrialized states in India and the Hazira Field is located adjacent to one of India's largest industrial areas. This area is serviced by the pipelines referred to below.

Gujarat Gas Company Limited ("**GGCL**"), the Indian subsidiary of British Gas PLC, owns an 18-inch and an 8-inch gas sales line going from the Hazira Field to residential and industrial users. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area.

A GBA designed to allocate natural gas in reservoirs known to be continuous across the Hazira/Gauri block boundary, went into effect on February 17, 2006. Reserves within these reservoirs will now be shared equitably between the Gauri and Hazira interest-holders, rather than resorting to unitization. The GBA does not affect Niko's working interest amount in the Hazira Field. The GBA provides an arrangement whereby the gas reserves on each permit are determined periodically and production for zones which exist on both permits is allocated to ensure each party draws the reserves that are attributable to its property.

The following were the significant gas sales contracts in place for the Company for gas from the Hazira Field for Fiscal 2008 and the current gas prices for these contracts:

Purchaser	Abbreviation	Contract Start	Contract Expiry	Minimum Take-or-pay	Maximum Purchase at Contracted Price	Actual Purchase for Fiscal 2008	Contract or Current Price	% of Total Sales for Fiscal 2008	% of Total Sales for Fiscal 2007
Gujurat State Energy Generation Ltd.	GSEG	February 2000	April 2016	18.1 MMcf/d gross (6.0 MMcf/d net)	24.9 MMcf/d gross (8.5 MMcf/d net)	21.6 MMcf/d gross (7.2 MMcf/d net)	US$4.05/mcf	6%	21%
Essar Power Ltd.	Essar	October 2002	December 2007	16.4 MMcf/d gross (5.5 MMcf/d net)	22.6 MMcf/d gross (7.5 MMcf/d net)	16.2MMcf/d gross(1) (5.4 MMcf/d net)	US$4.50/Mcf	11%	21%

Note:

(1) The Company was unable to deliver the minimum quantity to the customer during the period.

All natural gas contracts are US dollar-denominated and the prices for Fiscal 2008 were the Indian Rupee equivalent of US$3.51 per Mcf to US$4.50 per Mcf. Sales under the remaining 8 contracts, which commenced at various dates, accounted for 17% of consolidated sales of the Company for Fiscal 2008. The Essar contract and four additional contracts were not renewed and the Company currently has five contracts for the sale of gas from the Hazira Field, one of which expires in Fiscal 2009.

In accordance with natural gas sales contracts to customers in the vicinity of the Hazira field, the Company and its joint venture partner at Hazira have committed to certain minimum quantities. Should the Company fail to supply the minimum quantity of natural gas 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 will use D6 volumes to fulfill these past obligations and has signed a GBA to this effect. The GBA indicates that the Company's joint venture partner has supplied the shortfall up to the minimum quantity from other sources on behalf of the joint venture and the Company will provide five times the Company's shortfall quantity from gas produced from the D6 block. In the event the Company is unable to deliver the volumes, the Company will have a potential liability, which is currently estimated at US$27.0 million.

(b) Surat Block, India

In July 2001, Niko and the GOI executed a PSC covering the 419 square kilometre Surat Block located onshore adjacent to the Hazira Field in Gujarat State, India. Niko has a 100% interest in the Surat Block. Under the terms of the PSC, 395 square kilometres has been relinquished. Production from this shallow gas field commenced production in April 2004 and the natural gas is transferred to the customer via Niko's 6” pipeline to the customer's facility. In Fiscal 2008, three additional development wells were drilled and are currently on production.

A Gas Balancing Agreement was signed with Oil and Natural Gas Corporation in October 2004 to allocate the gas equitably from the Bheema # 1 zones.

All of the production from the Surat field is sold to one customer, GGCL. Under the terms of a contract extension signed with GGCL on March 31, 2005, the negotiated gas price was US$4.05 until June 18, 2007, US$4.50/Mcf until April 30, 2008 and US$5.00/Mcf until expiry on March 31, 2009.

(c) D6 Block, India

In April 2000, Niko, the GOI and Reliance signed a PSC for the D6. Niko has a 10% working interest in the block, with Reliance, being the operator, holding the remaining interest. The block is 7,645 square kilometres lying approximately 20 kilometres offshore of the east coast of India.

The Company's undeveloped reserves in India include the Dhirubhai 1 and 3 discoveries. The development of the discoveries is on schedule for production of gas during the third calendar quarter of 2008. The wells and facilities are substantially complete. The Company's share of the Phase I initial field development costs are estimated at US$520 million of which US$348 million has been spent as at June 24, 2008.

Conceptual studies are underway for the development of eight natural gas discoveries. The discoveries are adjacent to the Dhirubhai 1 and 3 gas fields that are currently under development. It is intended that these satellite discoveries be tied back to Dhirubhai 1 and 3 facilities and utilise the same transmission pipelines.

The Company's undeveloped reserves in India include the Cretaceous oil discovery (MA). Development plans for the Cretaceous oil discovery (MA) were approved by the Government of India in April 2008. The wells, the FPSO and other facilities are substantially complete. Drilling of the first two horizontal development wells, MA4H and MA3H, was completed in October and November 2007, respectively. Production is expected to commence in the third calendar quarter of 2008. The field development costs are estimated at US$1.5 billion (US$150 million net to the Company) and the Company has spent US$71 million as at June 24, 2008.

The GOI has approved the pricing formula for the sale of gas to be produced from the D6 Block, which currently results in a gas price of US$4.20 per MMBtu.

(d) NEC-25, India

In April 2000, Niko, the GOI and Reliance signed a PSC for the NEC-25 block. Niko has a 10% working interest in the block, with Reliance, being the operator, holding the remaining interest. The block comprised 14,535 square kilometres lying offshore adjacent to the east coast of India and 3,780 square kilometres have been relinquished as required under the PSC. 3D seismic of 3,500 square kilometres, or 32% of the block, has been shot on the block.

A total of 6 gross (0.6 net) wells were drilled on the initial seismic area resulting in six gas discoveries. During Fiscal 2006, the GOI, Reliance as operator and Niko declared commerciality of these six natural gas discoveries, which are all within the original 1,800 square kilometre 3D seismic area. Development plans for the six discoveries that have been declared commercial by the Indian regulatory authorities have been prepared, were approved by the Joint Venture's Operating Committee in May of 2007 and subsequently submitted to the Government of India. Costs and timing for commercial production will be disclosed upon approval of the development plan. In Fiscal 2007, the Company drilled two exploration wells resulting in a discovery and a dry hole. In Fiscal 2008, an additional three wells were drilled. Based on data obtained from logging and MDT, the presence of hydrocarbons was confirmed in the three wells.

(e) Cauvery Block, India

The Company was awarded 100% interest in the Cauvery Block, which is located onshore southeast India in the State of Tamil Nadu, in the NELP-V bidding round in 2005. The block has mainly oil potential. The block covers 957 square kilometres and a total of 915 square kilometres of seismic data had been acquired on the block. The seismic is currently being processed and drilling prospects will be identified to allow drilling of three new locations in late 2008 or early 2009. These three new locations, the two wells already drilled, which were dry holes, and additional seismic will fulfill the Phase I commitment. The remaining capital expenditures for the drilling under the Phase I commitment are estimated at US$7.5 million and seismic is currently being evaluated with the objective of drilling three new prospects in fiscal 2009.

(f) D4 Block, India

In September 2005, the Government of India, Niko and Reliance signed a PSC for the D4 Block. Niko has a 15% participating interest in the block, with Reliance, being the operator, holding the remaining interest. The Block is 17,050 square kilometres, lying offshore of the east coast of India in the Mahanadi Basin, was awarded in the NELP-V bidding round in 2005 and has natural gas potential. Under Phase I commitments, 2,366 kilometres of 2D seismic was acquired over the block. Processing of the seismic and interpretation of the data has been completed. Based on the analysis, a further 2,800-kilometres 2D seismic program and a 3,600-square-kilometre 3D seismic program have been designed and acquisition is underway with completion expected in late calendar 2008. Once the new seismic data is processed and interpreted, initial drilling locations will be selected, possibly as early as mid-2009 to fulfill the Phase I work commitment. Estimated cost of the Phase I work commitment is US$97.6 million (US$14.6 million net) and must be completed within 4 years of obtaining the Production Exploration License.

(g) Terms of the Indian PSCs

Under the terms of the PSCs for the Company's Hazira and Surat Blocks, the onshore Cauvery Block and the three offshore blocks, the GOI is the sole owner of the oil and gas reserves thereunder except in regard to that part of the reserves where the title has passed to the Company and its partner in accordance with the provisions of the PSC. The material terms of the PSCs are the same for each of the fields and blocks, except as noted below:

<u>All Fields and Blocks</u>

The PSCs for all of the Company's six Indian fields and blocks provide:

(i) for granting the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities;

(ii) for enabling the Company to recover all exploration, development and production costs and expenses incurred for a field or block from the petroleum produced from that field or block;

(iii) for the right to market natural gas to third parties at a market determined price;

(iv) for the right to market crude oil produced into the domestic market at international prices;

(v) that at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks are returned to the GOI;

(vi) for the setting of royalties payable to the GOI;

(vii) that the GOI has the right to terminate the PSCs on 90 days' notice upon the occurrence of certain events, including the extraction by Niko or its partners of hydrocarbons in contravention of the PSC or without the authority of the GOI, Niko or its partners being declared bankrupt, the assignment by Niko or its partners of any interest in a PSC without the appropriate consents of the GOI, the failure by Niko or its partners to make monetary payments under the PSCs when due and the failure of Niko or its partners to comply, in a material manner, with the terms of the PSCs or any license or lease issued thereunder; and

(viii) that on the expiry or termination of a PSC or relinquishment of part of a contract area under a PSC, the operator will remove all equipment and installations in a manner agreed with the GOI pursuant to an abandonment plan and the operator will perform all necessary site restoration activities in accordance with good international petroleum industry practice.

<u>Hazira Block</u>

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Hazira field provides:

(i) for appointing the Company as operator of the fields;

(ii) for a formula for sharing in the profit oil and gas produced from each field between the Company, its partner and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced once the Company and its partner have recovered 100% of their investment in the field from after tax cash flows. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko and its partner according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.0	0%
1.0 – 1.5	10%
1.5 – 2.0	20%
2.0 – 2.5	25%
2.5 – 3.0	35%
>3.0	40%

(iii) The formula for the GOI entitlement on all the PSCs is calculated on a cumulative basis at March 31 each year by field and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures; and

(iv) for the term for the fields of 25 years from September 1994 with provision for the GOI to grant a maximum of two five-year extensions;

Surat Block

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Surat Block provides:

(i) for appointing the Company as operator of the block;

(ii) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, the GOI is entitled to a 20% interest in the profit oil and gas produced. There is no profit oil and gas until the Company has recovered 100% of its investment in the field. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.5	20%
1.5 – 2.0	30%
2.0 – 2.5	40%
2.5 – 3.0	50%
>3.0	60%

The formula for the GOI entitlement is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures.

(iii) that the Company reprocess the existing 2D seismic, shoot 250 square kilometres of 3D seismic and drill 15 wells in the first phase of the work commitment. An optional phase of the work commitment undertaken by the Company required the Company to shoot 50 square kilometres of 3D seismic and drill five wells. The Company completed all the work commitments for the first phase and elected not to proceed to the second two-year phase for exploration in the year ended March 31, 2004. Accordingly, the non-productive lands have been surrendered.

(iv) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production;

(v) that the PSC for the onshore block expires when the license for the block expires; and

(vi) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

Offshore Blocks

In addition to the terms referred to under "All Fields and Blocks" above, the PSCs for the 3 offshore blocks in which Niko has retained an interest provide:

(i) for appointing Reliance as operator of the offshore blocks;

(ii) for a formula for sharing in the profit oil and gas produced from the blocks between the Company, Reliance and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs for NEC-25 and the D6 Block, 90% of revenue can be used to recover costs and under the terms of the PSC for the D4 Block, 80% of revenue can be used to recover costs. Under the terms of the PSCs, the GOI is entitled to a 10% interest in the profit oil and gas produced if the Company and Reliance have recovered less than 150% of their investment in the field from cash flows. The GOI entitlement escalates on a formula basis with the GOI share increasing as a greater multiple of the investment is recovered according to the following investment multiples for NEC-25, the D6 Block and the D4 Block:

	GOI Entitlement		
Investment Multiple	NEC-25	D6	D4
0.0 – 1.5	10%	10%	10%
1.5 – 2.0	16%	16%	10%
2.0 – 2.5	22%	28%	19%
2.5 – 3.0	28%	85%	70%
3.0 – 3.5	70%	85%	76%
>3.5	70%	85%	85%

The formula for the GOI entitlement on all the PSCs is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(iii) that each block has a specific work commitment, which would include reprocessing existing 2D seismic, shooting new 2D and 3D seismic and drilling one, two or three wells in the first phase of the work commitment. Subsequent work phases are optional and would include additional seismic and wells. In the event that, at the end of the relevant phase of work commitment or at the time of the early termination of the PSC by the GOI for any reason whatsoever, the minimum work program under the PSC for that phase has not been fulfilled, the Company is required to pay to the GOI its participating working interest share of the amount of funds that would be required to complete such minimum work program;

(iv) that the Company is required to relinquish up to 25% of the block at the end of the first phase of the work commitment. At the end of the subsequent work phases, the Company loses up to an additional 25% of the block in the case of NEC-25 and the D6 Block and 50% of the block in the case of the D4 Block. In all cases, the Company can retain the development and discovery areas;

(v) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production, however, there is a minimum alternative tax. There is currently confusion in India regarding the applicability of this tax holiday to natural gas;

(vi) that, subject to earlier termination of the PSC, the PSC for a block expires when the license for the block expires; and

(vii) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

<u>Cauvery Block</u>

In addition to the terms referred to under "All Fields and Blocks" above, the PSC for the Cauvery Block provides:

(i) for appointing the Company as operator of the block;

(ii) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GOI. Under the terms of the PSC, 90% of the revenue can be used to recover costs. The remaining profit oil and gas is shared with the GOI being entitled to 10% of the profit oil and gas produced if the Company has recovered between 0% and 150% of its investment in the field from cash flows. The GOI entitlement escalates on a formula basis with the GOI share of profit oil and gas increasing as a greater multiple of the investment is recovered by Niko according to the following investment multiples:

Investment Multiple	GOI Entitlement
0.0 – 1.5	10%
1.5 – 2.0	20%
2.0 – 2.5	30%
2.5 – 3.0	30%
3.0 – 3.5	35%
>3.5	50%

The formula for the GOI entitlement is calculated on a cumulative basis at March 31 each year and the results of the calculation establish the sharing ratio for the next year. The GOI entitlement is applied to the pre-tax cash flow from the field after deducting allocated overhead and capital expenditures;

(iii) that the Company is required to reprocess the existing 2D seismic, shoot 550 square kilometres of 3D seismic and drill five wells in the first phase of the work commitment. The second phase of the work commitment, which is optional, requires the Company to drill two wells. The third phase of the work commitment, which is optional, requires the Company to drill two wells.

(iv) that the Company is required to (i) relinquish 25% of the block at the end of the first phase of the work commitment, (ii) relinquish 50% of the block at the end of the second phase of the work commitment, and (iii) relinquish all areas but the development and discovery areas at the end of the third phase of the work commitment;

(v) that the Company is entitled to a seven-year tax holiday commencing from the first year of commercial production, however, there is a minimum alternative tax. There is currently confusion in India regarding the applicability of this tax holiday to natural gas;

(vi) that the PSC for the onshore block expires when the license for the block expires; and

(vii) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to a "Site Restoration Fund" in accordance with the scheme framed by the GOI.

In addition to the above, the GSPC JOA governs the operation of the Hazira fields and the Reliance JOAs, between the Company and Reliance, govern the operations of the D6 Block, NEC-25 and the D4 Block. The GSPC JOA provides for the respective participating interests of the Company and GSPC in the Hazira field, the sharing of costs associated with the development of, and production from, the fields in accordance with their respective interests and covers such items as appointing the Company operator and outlining the duties of the operator, how the oil and gas produced is sold, accounting procedures and expenditure approval levels. The Reliance JOAs cover similar items with respect to the D6 Block, NEC-25 and the D4 Block as between the Company and Reliance.

Bangladesh

The Company has an interest in two natural gas fields (Feni and Block 9) that are producing in Bangladesh. During Fiscal 2008, one customer purchasing production from Bangladesh accounted for approximately 43% of consolidated revenue. During Fiscal 2007, one customer purchasing production from Bangladesh accounted for approximately 36% of consolidated revenue. Markets, distribution methods, significant gas sales contracts and changes to gas sales contracts for individual properties are discussed in this section under "Chattak and Feni Gas Fields, Bangladesh" and "Block 9, Bangladesh". The Chattak field is not fully developed and future drilling activities at this field have been postponed pending resolution of overdue payments for gas owed to the Company by the Government of Bangladesh. Natural gas demand exceeds the current production levels in Bangladesh and as a result, the Company is able to sell all of it's production to the Government of Bangladesh.

(a) Chattak and Feni Gas Fields, Bangladesh

In August 1999, the Company signed a Framework of Understanding with BAPEX for the evaluation of the Chattak and Feni fields, being natural gas fields onshore Bangladesh.

On October 16, 2003, a joint venture agreement was entered into between Niko Resources (Bangladesh) Ltd. (a wholly-owned subsidiary of Niko Resources Ltd.) ("**NRBL**") and BAPEX for the joint development of the Chattak and Feni fields (the "**JVA**"). The Chattak field is 376 square kilometres and the Feni field is a total of 43 square kilometres in size.

The Company completed a successful three-well drilling program in Feni during Fiscal 2005. Production from the field commenced in November 2004. Further activity has been pending resolution of overdue payment for gas owed to NRBL by the Government of Bangladesh.

The Company supplies all of the gas production from the Feni field to Petrobangla, the Bangladesh government state oil and gas company. From the commencement of production in November 2004 to December of 2006, the Company had been supplying the gas without a sales contract in place and without a negotiated gas price. During this time, the Company received US$4 million of the total outstanding receivable for gas delivered. The Company and Petrobangla signed a gas purchase and sale agreement in December of 2006 with a price of US$1.75/Mcf with application to all volumes delivered prior to signing the agreement that expires in November 2009 and may be extended upon mutual agreement by the parties. As at March 31, 2008, Petrobangla owed US$25.3 million to NRBL for gas delivered to Petrobangla from the Feni field, which remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field. Petrobangla has agreed to provide access to its pipeline system on a priority basis for distribution of the natural gas, provided that there is spare capacity at that time.

In Chattak, the upper fault block on the west side of the block has produced in the past from one well that was previously drilled on the property, while a downthrown fault block on the east side of the block has not been drilled. The Company acquired approximately 200 square kilometres of 3D seismic on the Chattak structure and drilling began in December 2004. In January 2005, while tripping pipe at 807 metres, the well encountered an uncontrolled gas flow and the well and rig were damaged beyond repair. The Company proceeded to construct a drilling location to accommodate the relief well drilling operation to stop the uncontrolled flow of natural gas that occurred at the Chattak-2 well location. The relief well spudded in May 2005 and near the end of June 2005, a second uncontrolled flow of natural gas resulted in the destruction of the drilling rig. The Company then proceeded to construct a second relief location and contracted a drilling rig to attempt a second relief well. By October 2005, the Company was successful in achieving intersection with the original blowout well and was able to pump sufficient cement into the blowout well to stop the flow of natural gas from the reservoir. Since stopping the flow from the reservoir, the drilling locations have been successfully restored.

The Company finished construction of a natural gas processing facility at Chattak field capable of handling up to 50 MMcf of natural gas per day. A 16-inch diameter, 16-kilometre pipeline from Chattak to the tie-in point with Jalalabad Gas Transmission and Distribution Ltd. was completed, pressure tested, and is ready for use. In addition, the preparation of the drilling location for the East Chattak well has been completed.

Currently, the Company does not have a well in Chattak that is capable of production. The Company's drilling program has been postponed pending further developments in the various disputes between the Company and the Government of Bangladesh.

Under the terms of the JVA:

(i) NRBL and BAPEX agree to jointly explore and develop the Chattak and Feni fields with NRBL assuming the role as operator and assuming all the costs and risks of the exploration and development;

(ii) the term of JVA is the lesser of 20 years and the full economic producible life of the gas fields;

(iii) title to assets acquired by, and to data obtained or compiled by, NRBL in connection with operations is vested in BAPEX and, at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the lands are to be turned over to BAPEX;

(iv) NRBL and BAPEX agree to sell any production to Petrobangla or its designee(s) under the terms of a sales agreement to be entered into and a price to be determined through negotiations at that time; if Petrobangla is not able to provide a market for the production from the fields, NRBL and BAPEX have agreed to sell their production to the Bangladesh domestic market;

(v) Petrobangla has agreed to provide access to its pipeline system on a priority basis provided that there is spare capacity at that time;

(vi) on the expiry or termination of the JVA or relinquishment of part of a contract area thereunder, the equipment and installations will be removed by NRBL pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(vii) BAPEX has the right to terminate the JVA on 90 days' notice upon the occurrence of certain events, including NRBL (i) failing to make monetary payments thereunder when due (with such failure continuing for 30 days), (ii) failing to meet and fulfill its duties and obligations in accordance with the JVA, or (iii) committing any act which is contrary to the interests of Bangladesh, provided that NRBL will have the ability to remedy any breach during that period; and

(viii) a formula is established for sharing the oil and gas produced among NRBL and BAPEX. Under the formula, BAPEX is entitled to 20% of the production from the Chattak "west" and Feni fields and 25% of the production from the Chattak "east" field until such time as NRBL has recovered up to 100% of its investment (determined in accordance with the formula), respectively, in those fields: BAPEX's share of production thereafter escalates as a greater multiple of the investment is recovered according to the following investment multiples for Chattak West, Feni and Chattak East:

	BAPEX Entitlement	
Investment Multiple	Chattak West and Feni	Chattak East
0.0 – 1.0	20%	25%
1.0 – 1.5	25%	30%
1.5 – 2.0	32%	38%
2.0 – 3.0	38%	43%
> 3.0	42%	50%

As a result of the uncontrolled releases of natural gas described above, three law suits were brought against the Company:

(i) During the year ended March 31, 2006, the Company was named as a defendant in a lawsuit that was filed in Texas by a number of plaintiffs who claim to have suffered damages as a result of the uncontrolled releases of natural gas that occurred at the Chattak-2 well in Bangladesh in January and June 2005. Total damages sought were in excess of US$250 million. On July 7, 2006, a court hearing was held to hear the Company's pleadings for the lawsuit to be dismissed due to lack of jurisdiction in Texas. The court in Texas dismissed the lawsuit on August 25, 2006 and the plaintiffs appealed the dismissal. The appeal was heard on July 10, 2007 and the appeal has been dismissed. The plaintiff did not appeal the second dismissal. As a result, the lawsuit is dismissed with no financial impact to the Company.

(ii) During the year ended March 31, 2006, a group of petitioners in Bangladesh (the petitioners) filed a writ with the Supreme Court of Bangladesh (the Supreme Court) against various parties including NRBL, a subsidiary of Niko Resources Ltd. The petitioners are requesting the following of the Supreme Court with respect to the Company:

(A) that the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal;

(B) that the government realize from the Company's Bangladesh subsidiary compensation for the natural gas lost as a result of the uncontrolled flow problems as well as for damage to the surrounding area;

(C) that Petrobangla withhold future payments to the Company's Bangladesh subsidiary relating to production from the Feni field (US$25.3 million as at March 31, 2008); and

(D) that all bank account of the Company's Bangladesh subsidiary maintained in Bangladesh be frozen.

At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of NRBL. This freeze was lifted shortly thereafter, allowing NRBL to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by NRBL to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of NRBL that are located outside of the country. If this legal action is determined negatively against NRBL, it could result in the cancellation of NRBL's interest in the Feni and Chattak fields as well as imposition of relief against it as detailed in (ii), (iii) and (iv) above which could have an adverse impact on the Company's Bangladesh subsidiary and its financial position.

During the year ended March 31, 2006, NRBL received a letter from Petrobangla, a Bangladesh crown corporation, demanding compensation related to the uncontrolled flow problems that occurred in the Chattak field in January and June 2005. The Company has repeatedly offered to resolve the claims through international arbitration. Petrobangla went so far as to appoint local counsel to represent it in the proposed arbitration. The Company's counsel and Petrobangla's counsel met in Dhaka in September of 2007 to discuss an agreement that would facilitate such an arbitration. The arbitration agreement was never concluded.

On May 29, 2008, NRBL received a letter dated May 27, 2008 from a Dhaka law firm representing Petrobangla. The Legal Notice appeared to be the equivalent of a demand letter under Canadian law. The legal notice referenced the Joint Venture Agreement between NRBL and Bangladesh Petroleum Exploration & Production Company Ltd. (BAPEX), a wholly owned subsidiary of Petrobangla. The operations at Chattak at the time of the blowouts were being conducted pursuant to the JVA. The Legal Notice asserted that NRBL was wholly liable for alleged losses from the Chattak blowouts, which were asserted to be in the amount of 746.50 Crore Taka (approximately $107 million). The claimed losses were set out in Crore Taka as follows: for gas burnt at the Chattak field – 36.5; for sub-surface loss at Chattak field – 72.35; for environmental loss – 84.56; and for additional sub-surface loss at Chattak field – 552.75.

The Legal Notice sought payment from NRBL in the full amount within 15 days, failing which legal action would be pursued. NRBL replied to Petrobangla's counsel within the 15 day period denying liability for the blowouts, denying that damages as alleged had been suffered and asserting that the claims were properly the subject of arbitration, not a court action.

On June 17, 2008, NRBL learned that a lawsuit had been commenced against it and other parties by GOB and Petrobangla. The 77 page pleading seeks damages from the defendants, jointly and severally, in the amount of 746.50 Crore Taka, together with interest at 12% per annum from June 24, 2005 until satisfaction of any judgement. The first hearing date has been set for July 31, 2008 in Dhaka. NRBL is consulting with its counsel with respect to its response to the Bangladesh action. The responses may include bringing an application to the Bangladesh court to stay the action on the grounds that the claims are properly the subject of arbitration agreements.

The Company remains of the view that NRBL has a good defence to the claims on the merits. It is also strongly of the view that the claims ought to be resolved through international arbitration in accordance with the agreements between NRBL, Petrobangla and BAPEX, and it intends to vigorously assert that position. The ultimate resolution of the claims and the timing of such resolution is uncertain. Any negative result to the Company and its subsidiary NRBL could have an adverse impact on the Company and its financial position.

The Company and the Government of Bangladesh had previously agreed to settle the government's claims through arbitration conducted in Bangladesh based upon international rules. The Company will actively defend itself against the lawsuit. This process could take in excess of three years. There can be no assurances as to the outcome of the lawsuit and the associated cost to the Company. Any negative result to the Company's Bangladesh subsidiary could have an adverse impact on the Company and its financial position.

(b) Block 9, Bangladesh

On September 17, 2003, Niko, through its indirect wholly-owned subsidiary, Niko Resources (Cayman) Ltd., acquired all of the shares of CIBL, an indirect subsidiary of ChevronTexaco Corporation ("**ChevronTexaco**"). CIBL (now called Niko Exploration (Block 9) Limited) holds a 60% interest in the PSC (the "**Block 9 PSC**") issued by the Government of Bangladesh for Block 9. In addition, CIBL is responsible for the costs associated with a 6.67% carried interest in the Block 9 PSC held by BAPEX.

Block 9 covers approximately 6,880 square kilometres of land in the central area of Bangladesh surrounding Dhaka. There have been 450 square kilometres of 3D seismic and 1,010 kilometres of 2D seismic shot on the Block 9 lands. Three wells were drilled, the first of which was abandoned. The second well, the Lamlai-3 well, was drilled to evaluate the southern end of a large anticlinal structure. A 620 square kilometre 3D seismic program over the Lalmai/Bangora anticline was completed during Fiscal 2006. In May 2006, as the natural gas facilities were being completed, long-term test production of the third well, Bangora-1, commenced. Bangora-2, Bangora-3, Bangora-4 and Bangora-5 were drilled in Fiscal 2007. Future costs to fully develop the proved reserves include the tie-in of two existing wells and construction of facilities for these wells.

The initial three-year exploration period under the Block 9 PSC was to expire on April 11, 2004. A series of extensions were granted extending the exploration period.

The Company has signed a temporary GPSA including a price of US$2.34 per MMbtu, which expires June 30, 2008. The Company expects to sign the permanent GPSA, on June 30, 2008. The price is expected to be consistent with the temporary GPSA and the permanent GPSA will expire 25 years from the approval of the development plan, in the event commercial production ceases or if the PSC is terminated. Petrobangla is the sole purchaser of natural gas production from Block 9. The sales delivery point is at Niko's facility and thereafter is the responsibility of the Petrobangla and is transported via their Trunk Pipeline.

The Block 9 PSC was executed and issued effective April 11, 2001 among Petrobangla, BAPEX, Tullow Bangladesh Limited, CIBL and Texaco Exploration Asia Pacific Regional Pathfinding Inc. Under the terms of the Block 9 PSC, the Government of Bangladesh is the sole owner of any oil and gas reserves under the Block 9 lands. The Block 9 PSC further provides:

(i) for the granting to the participants thereunder of the right to conduct petroleum operations;

(ii) for the enabling of the participants to recover all exploration, development and production costs and expenses incurred for the block from the oil and gas produced from the block;

(iii) for the joint and several liability of the participants for their obligations under the Block 9 PSC;

(iv) for an initial exploration period of three years, two further successive exploration periods of two years each (provided the required work commitment in each previous period is completed) and, in the event of a commercial discovery, a production period of 20 years for oil production and of 25 years for natural gas production.

(v) for work commitments (i) in the initial exploration period, of acquiring, processing and analyzing at least 1,000 kilometres of 2D seismic and drilling at least 10 wells of varying depth, (ii) in the first further exploration period, of acquiring, processing and analyzing at least 400 kilometres of 2D seismic and drilling 4 wells of varying depth, and (iii) in the second further exploration period, of acquiring, processing and analyzing at least 600 kilometres of 2D seismic and drilling 6 wells of varying depth; in the event of commercial discovery, Niko will be required to submit a development plan for approval by Petrobangla.

(vi) for the relinquishment of 25% of the block at the end of each of the initial exploration period and the first successive exploration period. In the event that there is no commercial discovery in the block by the end of the last exploration period, the Block 9 PSC will terminate. In the event that a production area has been established in the block and thereafter normal production ceases (for reasons other than force majeure) for a period in excess of 180 consecutive days, the participants are required, in certain circumstances, to relinquish the right to conduct petroleum operations upon the request of Petrobangla;

(vii) that, in the event that the participants wish to voluntarily relinquish their rights in the block prior to the completion of the work commitments or at the end of an exploration period the work commitments have not been completed, the participants will be required to pay to Petrobangla certain amounts intended to correspond to the cost of the remaining work under the work commitments and to provide bank guarantees to secure such payments;

(viii) for the sharing in the profit oil and gas among the participants and Petrobangla. Under the terms of the Block 9 PSC (i) during the period of cost recovery, the contractor shall recover all costs and expenses in respect of all exploration, development, production, operations and related activities to the extent of a maximum of 40% of per calendar year of all available oil and 45% per calendar year of all available natural gas, available condensate and available NGL. On the remaining 55%, the participants are entitled to declining percentages in accordance with the following:

Profit Natural Gas Petrobangla Entitlement

Production tranches	During Cost Recovery	After Cost Recovery
Up to 150 MMcf/d	61%	66%
Portion in excess of 150 MMcf/d and up to 300 MMcf/d	66%	72.5%
Portion in excess of 300 MMcf/d and up to 450 MMcf/d	72.5%	78%
Portion in excess of 450 MMcf/d and up to 600 MMcf/d	75%	82.5%
Portion in excess of 600 MMcf/d	82%	85%

Profit Oil Petrobangla Entitlement

Production tranches	During Cost Recovery	After Cost Recovery
Up to 10,000 bbls/d	67%	70%
Portion in excess of 10,000 bbls/d and up to 25,000 bbls/d	70%	75%
Portion in excess of 25,000 bbls/d and up to 50,000 bbls/d	75%	80%
Portion in excess of 50,000 bbls/d and up to 100,000 bbls/d	80%	85%
Portion in excess of 100,000 bbls/d	83%	90%

(ix) that the participants may produce annually a total volume of natural gas equal to up to 7.5% of the proven plus probable recoverable natural gas reserves on the lands as determined by the Society of Petroleum Engineers. Petrobangla has a right of first refusal to acquire the participants' share of natural gas production for domestic consumption in Bangladesh subject to terms to be negotiated at that time provided that the price to be paid by Petrobangla will be determined quarterly and will be 75% of the arithmetic daily average of Platt's Oilgram quotations of high sulphur fuel oil 180 CST, FOB Singapore for the six months ending on the last day of the second month preceding the start of the particular quarter (with a floor price, prior to the 25% discount, of US$70 per metric tonne and a ceiling price, prior to 25% discount, of US$120 per metric tonne) plus a further 1% discount. In the event that Petrobangla does not exercise its right of first refusal, the participants will be entitled to sell their share of natural gas production in the Bangladesh domestic market provided that the sale price is not less than the discounted price referred to above. Subject to Petrobangla's right of first refusal, the participants will also have the right to export their share and Petrobangla's share of natural gas production in the form of liquefied natural gas. The price at which liquefied natural gas may be sold for export must be approved by Petrobangla;

(x) for the right for Petrobangla to require the participants to provide, for the period of time required by Petrobangla, the participants' share of oil production (up to 25% of the participants' share of profit oil) to the Bangladesh domestic market at a price to be determined in accordance with the market at that time discounted by 15% (provided that such final price must be approved by Petrobangla);

(xi) that title to immoveable and moveable assets acquired by the participants, and to data obtained or compiled by the participants, in connection with operations under the Block 9 PSC is vested in Petrobangla and, at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the lands are to be turned over to Petrobangla;

(xii) that, on the expiry or termination of the Block 9 PSC or relinquishment of part of a contract area, the equipment and installations will be removed by the participants pursuant to an abandonment plan and all necessary site restoration activities will be performed in accordance with international petroleum industry practice;

(xiii) for the payment by the participants to Petrobangla of (i) discovery bonuses of US$2 million upon each commercial discovery of oil or natural gas, (ii) production bonuses increasing from US$1 million to US$5 million as production on the Block 9 lands increases from 10,000 bopd to 100,000 bopd of oil and from 75 MMcf/d to 600 MMcf/d of natural gas, (iii) contributions to research and development activities of Petrobangla equal to US$0.03 per barrel of the participant's share of profit oil, condensate and NGL production and US$0.004 per Mcf of the participant's share of profit natural gas (which amounts are not recoverable as costs); and

(xiv) that Petrobangla and the Government of Bangladesh have the right to terminate the Block 9 PSC on (i) 60 days' notice upon the occurrence of certain events, including the failure by any of the participants to make monetary payments under the Block 9 PSC when due and the failure to declare a commercial discovery within the time limits provided in the PSC, and (ii) 90 days; notice upon a material breach by any of the participants under the PSC, provided that such participants will have the right to remedy the breach during that period.

In addition, the Block 9 JOA provides for the respective participating interests of the participants under the Block 9 PSC and the sharing of costs associated in the development of and production from the lands and covers such further items as the appointment of the operator, outlining the duties of the operator, accounting procedures and expenditure level approvals. The Block 9 JOA provides that Tullow Bangladesh Limited is currently the operator. Under the terms of the Block 9 JOA, at any time after the first date of declaration of a commercial discovery, Niko may elect to become operator under the Block 9 PSC.

Pakistan

In March of 2008, Niko Resources (Pakistan) Limited signed four PSAs with the President of the Islamic Republic of Pakistan and Government Holdings (PVT.) Limited (GHPL) for four offshore blocks in the Arabian Sea near the city of Karachi. Niko has a 100% interest in these blocks which cover 9,920 square kilometres.

Terms of the PSAs

The material provisions of the PSAs for all of the Company's four Pakistan blocks include:

(a) for granting the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities;

(b) for the enabling of the Company to recover all exploration, development and production costs and expenses incurred in the block from the oil and gas produced from the block;

(c) for the right to market petroleum produced, except as required by GHPL to meet domestic demand, into the domestic market or elsewhere at the Company's election;

(d) for the right to retain abroad and freely make use of sale proceeds from the export of its share of petroleum produced from the properties;

(e) for production bonuses, training and employment spending for nationals of Pakistan, and required funding to marine research and annual acreage rental;

(f) that at the expiry of the PSAs, all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks are returned to the GHPL together with the abandonment funds that are required to be funded into an escrow account as per the agreement;

(g) for the fixing of royalties payable to the GHPL;

(h) for appointing the Company as operator of the blocks;

(i) for a formula for sharing in the profit oil and gas produced from the block between the Company and the GHPL. Under the terms of the PSAs, 85% of the revenue can be used to recover costs. The remaining profit oil and gas is shared with the GHPL being entitled to a percentage of the profit oil and gas produced depending on the type of production (Crude Oil/LPG/Condensate or Natural Gas), production level and depth of the wells. The GHPL entitlement escalates on a formula basis with the GHPL share of profit oil and gas increasing as cumulative production increases and is at higher rates when the wells are < 4,000 metres, > 4,000 metres below sea level or ultra-deep:

< 4,000 Metres below sea level, GHPL Entitlement			> 4,000 Metres below sea level (but not Ultra Deep Grid Areas) GHPL Entitlement		
Cumulative production (MMBbls)	Crude Oil/LPG/ Condensate	Natural Gas	Cumulative production (MMBbls)	Crude Oil/LPG/ Condensate	Natural Gas
0 – 100	20%	10%	0 – 200	5%	5%
> 100 – 200	25%	15%	> 200 – 400	10%	10%
> 200 – 400	40%	35%	> 400 – 800	25%	25%
> 400 – 800	60%	50%	> 800 – 1200	35%	35%
> 800 – 1200	70%	70%	> 1200 – 2400	50%	50%
>1200	80%	80%	>2400	70%	70%

Ultra Deep Grid Areas, GHPL Entitlement		
Cumulative production (MMBbls)	Crude Oil/LPG/ Condensate	Natural Gas
0 – 300	5%	5%
> 300 – 600	10%	10%
> 600 – 1200	25%	25%
> 1200 – 2400	35%	35%
> 2400 – 3600	45%	45%
>3600	60%	60%

The formula for the GHPL entitlement is calculated monthly on a cumulative basis and the results of the calculation establish the sharing ratio for the next month. Where production is from multiple depths, a formula is applied to calculate a weighted average. The GHPL entitlement is applied to the cash flow from the block;

(j) for an initial term of five years with two renewal periods of two years each;

(k) that the Company is required under Phase I to perform a minimum work obligation of $1 million for each block in the first and second contract years. Phase II includes a minimum work obligation of $1.6 million for each block in the third and fourth contract years. Phase III includes a minimum work obligation of $3 million for each block in the fifth contract year. The minimum work in Phase I and Phase II must include drilling an exploratory well in any of the four blocks;

(l) for the automatic and immediate termination of the agreement if the Company has not declared a significant gas discovery or a commercial discovery during the initial term, the first renewal, the second renewal or any extensions thereof; if the Company has not established commercial production from at least one commercial discoveries within seven years of the first declaration of commercial discovery; if the Company has only declared one or more significant gas discoveries and has not made a declaration of commercial discovery for at least one of such significant gas discoveries during the retention period; or if the Company has not requested or has not been granted an extension of the initial term or first renewal.

(m) for a lease for a period not exceeding 25 years upon approval of each development plan for a commercial discovery;

(n) that the Government of Pakistan has the right to terminate the PSAs upon the occurrence of certain events, including the Company's failure to conform to the arbitration provisions of the PSA, the Company providing false information to the Government, the extraction by the Company of hydrocarbons in contravention of the PSA or without the authority of the Government of Pakistan, the Company or its partners being declared bankrupt, the failure by the Company to make monetary payments under the PSAs when due, the Company's failure to deliver guarantees as per the PSA and the failure of the Company to comply, in a material manner, with the terms of the PSAs or any license or lease issued thereunder;

(o) that the Company is required to (i) relinquish 20% of the block at the end of the initial term of the license, (ii) relinquish not less than 30% of the block on or before the end of the first renewal period, (iii) relinquish not less than 30% of the block on or before the end of the second renewal period, and (iv) relinquish all areas but the development and discovery areas on or before the expiration of the exploration period;

(p) that the Company, within ten years of the commencement of commercial production from each commercial discovery, relinquish from the development area all sections which do not cover wholly or partially the vertical projections to the surface reservoirs from which Commercial production is being obtained;

(q) the Company is required to pay income taxes of 40% in accordance with the *Income Tax Ordinance,* 2001. These income tax laws allow costs incurred for one block to be deducted against profits of another block for the business of petroleum; and

(r) that the Company is responsible for restoration, including abandonment plans, and the funding of the same, including payment of any annual contributions to an escrow account for the estimated cost of abandonment.

Kurdistan

In May of 2008, the Nikoresources (Kurdistan) Ltd., a wholly owned subsidiary of the Company, entered into a PSC with Kurdistan Regional Government of Iraq (KRG) for an interest in an onshore block in Sulaymaniyah Governorate of the Federal Region of Kurdistan in Iraq, which covers approximately 846 square kilometres. The Company currently has a 36% interest and carries the proportionate cost for the government's interest resulting in a 45% cost interest. The KRG has the option, within eight months of the effective date of the PSC, of assigning to a third party/parties an aggregate of 20% of the contract area. The third parties would reimburse the joint venture partners for the costs incurred related to their interest except for any signature bonus or capacity building bonus. In the event this occurs, the Company will have a 27% interest and will carry the proportionate cost for the government's interest resulting in a 34% cost interest. Under both scenarios, the Company is able to recover the Company's costs and costs paid for the government's carried interest.

Terms of the PSC

The material provisions of the PSC for the Company's Kurdistan block include:

(a) for granting the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities;

(b) for enabling the Company to recover exploration, development and production costs and expenses in accordance with the agreement incurred for a field or block from the petroleum produced from that field or block;

(c) for the right to market crude oil produced, except as required to meet Kurdistan Region internal consumption requirements for crude oil;

(d) for the KRG to have the right to review and approve natural gas sales contracts;

(e) for a signature bonus, a capacity building bonus, production bonuses, annual acreage rental and predetermined funding to the KRG for costs for recruitment or secondment of personnel, training costs, community support and the environment fund;

(f) that at the end of the contract life, all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks are returned to the KRG together with any abandonment funds that may be funded into an separate account as per the agreement;

(g) for the fixing of royalties payable to the KRG;

(h) for appointing the Company as operator of the block;

(i) for a formula used to calculate the sharing in the profit oil and gas produced from the block between the Company and the KRG. Under the terms of the PSC, 43% of crude oil revenue and 53% of gas revenue can be used to recover costs. The Company receives a share in the remaining profit oil and gas increasing as a greater multiple of the investment is recovered by the joint venture, depending on product type, in accordance with the following formulas:

Profit Crude Oil		Profit Natural Gas	
Investment Multiple	Joint Venture	Investment Multiple	Joint Venture
0 – 1	32%	0 – 1	38%
>1 – 2.25	$\frac{32 - (17)*(IM - 1)}{(1.25)}$	>1 – 2.75	$\frac{38 - (18)*(IM - 1)}{(1.75)}$
> 2.25	15%	>2.75	20%

where "IM" equals the investment multiple calculated as cumulative revenues divided by cumulative costs allowable for cost recovery. The formula for the KRG entitlement is calculated biannually on a cumulative basis and the results of the calculation establish the sharing ratio for the next period. The KRG entitlement is applied to the cash flow from the block excluding royalties, signature bonus, capacity building bonus and any production bonuses as deductions;

(j) for an initial exploration period of five years, extendable on a yearly basis up to a maximum period of seven contract years;

(k) that the Company is required under the first sub-period of the initial term (three contract years, extendable) to perform geological and geophysical studies, a data search on the contract area, field work, 300 line kilometres of 2D seismic and drill one exploration well. The second sub-period of the initial term (two contract years, extendable) includes further 2D or 3D seismic data and drilling one exploration well;

(l) for termination of the agreement if no commercial discovery has been made at the end of the exploration period, including any extensions thereof. In the event of a discovery, the exploration period can be extended up to two additional years to evaluate the discovery. In the event the discovery is not declared a commercial discovery, the agreement terminates;

(m) for a development period for a commercial discovery of 20 years. If commercial production is still possible at the end of its development period, the Company is entitled to an extension of 5 years;

(n) for the KRG (or a public company appointed by the government) to have a carried interest of 20% in the block, the costs of which are born by the Company and its joint venture partners. The Company and its joint venture partners are entitled to recover the petroleum cost associated with the carried interest;

(o) that the KRG has the right to terminate the PSC with 90 days notice and failure of the Company to remedy the default, upon the occurrence of certain events, including: the Company's failure to meet a material financial obligation of the PSC; failure to carry out work commitments; the interruption of production for a period of more than 90 consecutive days with no reasonable cause of justification; the extraction of hydrocarbons by the Company in contravention of the PSC or without the authority of the KRG; the Company and its partners being declared bankrupt; the Company's wilful refusal to abide by the arbitration provisions of the agreement; the change of control of the Company for which the KRG has not given authorization; and the failure of the Company to comply, in a material manner, with the terms of the PSC or any license or lease issued thereunder;

(p) that the Company is required to (i) relinquish 25% of the net area at the end of the initial term with the net area being determined by subtracting the production areas from the initial contract area, (ii) relinquish 25% of the net area at the end of the first extension period, (iii) relinquish all areas that are not production areas at the end of the exploration period; and

(q) that the Company is responsible for decommissioning costs for the decommissioning and/or removal and/or abandonment and making safe all of the Assets and site restoration and remediation.

Canada

The Company has a 45% non-operated interest in the Cullen unit in Saskatchewan. It produced 76 bopd gross (34 bopd net) in Fiscal 2008 (Fiscal 2007 – 76 bopd gross (34 bopd net)).

Oil and Gas Wells

The following table summarizes the Company's interests in India and Bangladesh, as at March 31, 2008, in oil and gas wells:

Producing and Non-Producing Wells
As at March 31, 2008

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing[1]						
India	1	0.3	43	21.7	44	22
Bangladesh	-	-	6	4.8	6	4.8
TOTAL PRODUCING	1	0.3	49	26.5	50	26.8
Non-producing[2]						
India	-	-	-	-	-	-
Bangladesh	-	-	3	1.8	3	1.8
TOTAL NON-PRODUCING	-	-	3	1.8	3	1.8

Notes:

(1) Includes wells that are temporarily shut-in but which are capable of production.

(2) Includes wells that are not capable of production but that are not yet abandoned.

The Hazira field in India has 9 gross (3.0 net) gas wells and 1 gross (0.3 net) oil wells located offshore, 17 gross (5.7 net) gas wells located on the land based drilling platform and 5 gross (1.7 net) gas wells onshore. Not included in the above table is one gross (0.3 net) well that is an injector well in Hazira. There are two pipelines, a gas plant and an oil facility at Hazira.

The Surat field in India has 12 gross (12 net) gas wells located onshore, all of which are producing. There is a gas plant at Surat.

There are 6 gross (3.6 net) onshore wells in Block 9. Three are currently producing and the remaining three are not included in the above table as they have been drilled but not tied in. There is a gas plant at Block 9.

The Feni field in Bangladesh has 3 gross (3 net) gas wells located onshore, two of which are producing. The remaining well is capable of production and is currently shut-in. There is a gas plant at Feni.

Not included in the above table are a total of 38 gross (3.8 net) offshore gas wells and 3 gross (0.3 net) offshore oil wells in the D6 Block in India that have been drilled, but not tied in. Development of the natural gas discoveries, 17 gross (1.7 net) gas wells in Dhirubhai 1 and 3, and the oil discoveries, 3 gross (0.3 net) oil wells in MA, in the D6 Block is continuing on schedule and production is expected to commence in the third calendar quarter of 2008. Facilities related to the gas development include onshore facilities including the gas plant and offshore facilities. Facilities related to the oil development are for offshore facilities including the FPSO.

Not included in the above table are 9 gross (0.9 net) wells in NEC-25 that have been drilled but not tied in. The field development was submitted to the GOI for the NEC-25 Block during Fiscal 2008. See “Oil and Gas Properties – India – NEC-25, India” for an update on development of this block.

Properties with No Attributed Reserves

The following table summarizes information with respect to the Company's properties to which no reserves have been specifically attributed:

Land Holdings With No Attributed Reserves
as at March 31, 2008

	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2009 (Acres)	
	Gross	Net	Gross	Net
India	8,486,799	1,307,989	-	-
Bangladesh	1,795,383	1,116,503	-	-
Pakistan	2,450,240	2,450,240	-	-
TOTAL	12,732,422	4,874,732	-	-

Reserves have not been specifically attributed to the Cauvery, D4 and NEC-25 blocks in India, the Chattak field in Bangladesh or the four blocks in Pakistan. For work commitments on the unproven properties, see "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – India" and "Statement of Reserves Data and Other Oil and Gas Information – Principal Properties – Bangladesh". Subsequent to March 31, 2008, the Company entered into a PSC for an interest in a block in Kurdistan. This adds 208,962 gross acres (56,420 net acres) to the unproved properties acreage. No Kurdistan land rights expire prior to March 31, 2009.

Forward Contracts

The Company has 6 gas contracts in India and 2 gas contracts in Bangladesh under which the Company may be precluded from fully realizing or may be protected from the full effect of future market prices for gas. See "Principal Properties – India – Hazira, India", "Principal Properties – India – Surat Block, India", "Principles Properties – Bangladesh – Feni and Chattak Fields, Bangladesh" and "Principle Properties – Bangladesh – Block 9, Bangladesh". In accordance with natural gas sales contracts to customers in the vicinity of the Hazira field, the Company and its joint venture partner at Hazira have committed to certain minimum quantities. Should the Company fail to supply the minimum quantity of natural gas 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 will use D6 volumes to fulfill these past obligations and has signed an agreement to this effect. Once the Company delivers production equal to five times the shortfall in accordance with the agreement, the Company will have discharged the potential liability, which is currently estimated at US$27.0 million.

Additional Information Concerning Abandonment and Reclamation

The Company estimates the abandonment and reclamation costs of wells, facilities and pipelines based on previously experienced abandonment and reclamation costs. The abandonment and reclamation costs related to Hazira for the land based drilling platform, the offshore platform and wells on the offshore platform are based on third party evaluations. The Company expects to incur these costs for 41.7 wells (net), 1.7 facilities (net), 0.3 pipelines (net), 0.3 land based drilling platforms (net) and 0.3 offshore platforms (net), being all of the obligations as at March 31, 2008. The amount of such costs expected to be incurred, net of estimated salvage value, is $49.3 million ($12.7 million discounted at 10%/year). A total of $1.4 million of abandonment and reclamation costs ($0.5 million discounted at 10%/year) have not been deducting in estimating future net revenues within the "Disclosure of reserves date" as these costs are for properties for which no reserves have been attributed. The Company expects to pay $5.5 million for abandonment and reclamation costs within the next three fiscal years.

Costs Incurred

For Fiscal 2008, the Company incurred the following costs on its properties:

Costs Incurred
Year Ended March 31, 2008 ($ thousands)

	India	Bangladesh	All Other
Property Acquisition Costs			
Proved Properties	-	-	-
Unproved Properties	-	-	-
Exploration Costs	52,300	1,946	411
Development Costs	276,561	7,145	5,768
	328,861	9,091	6,179

Exploration and Development Activities

For Fiscal 2008, the Company drilled the following exploration and development wells by country:

Exploration and Development Activities
Year Ended March 31, 2008
India

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	2	0.2
Gas	3	0.3	11	3.8
Service	-	-	-	-
Dry	2	2.0	-	-
Total	5	2.3	13	4.0

There were no wells drilled in Bangladesh during the year. In Thailand, the Company drilled two gross (1 net) exploration wells and performed three workovers on existing wells in Thailand that were unsuccessful. The Company exited Thailand during Fiscal 2008, disposing of these wells. There were no wells drilled in Canada during the year.

The Company's most important current and likely exploration and development activities are described under "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties".

Production Estimates

The following table provides the estimated volume of production of the Company from its India properties and Bangladesh properties derived from the Ryder Scott Report for Fiscal 2009:

Estimated Production[1]
For the Year Ended March 31, 2009

	Forecast Prices and Costs			
	Proved Reserves (gross)	Proved Reserves (net)[2]	Probable Reserves (gross)	Probable Reserves (net)[2]
India				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	61,666	60,096	463	353
NGL (Mbbl)	-	-	-	-
Light and Medium Oil (Mbbl)	597	582	22	20
Mboe	370,593	361,158	2,800	2,138
D6				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	54,407	53,863	-	-
NGL (Mbbl)	-	-	-	-
Light and Medium Oil (Mbbl)	552	546	12	12
Mboe	326,994	323,724	12	12
Hazira				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	4,811	3,784	463	353
NGL (Mbbl)	-	-	-	-
Light and Medium Oil (Mbbl)	46	36	10	8
Mboe	28,912	22,740	2,788	2,126
Surat				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	2,449	2,449	-	-
Mboe	14,694	14,694	-	-
Bangladesh				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	16,421	12,139	170	128
NGL (Mbbl)	19	14	-	-
Mboe	98,545	72,848	1,020	768
Feni				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	1,244	933	170	128
NGL (Mbbl)	1	1	-	-
Mboe	7,465	5,599	1,020	768
Block 9				
Estimated production for the year ended March 31, 2009				
Gas (MMcf)	15,177	11,206	-	-
NGL (Mbbl)	18	13	-	-
Mboe	91,080	67,249	-	-

Notes:

(1) These estimated production numbers represent the estimated production from the Hazira Field, the Surat Block and the D6 Block in India and the Feni field and Block 9 in Bangladesh. No reserves have been attributed to the Chattak field in Bangladesh, the NEC-25 block, the Cauvery Block and the D4 Block in India or the Pakistan blocks, so no production estimate is provided for those properties.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted including a reduction to reflect any profit petroleum amounts that will be payable to the Government of Bangladesh.

Production History

The following tables set forth the average daily production volumes, average price received, royalties, profit petroleum, production costs and the resulting netbacks for the periods indicated as at March 31, 2008:

Average Daily Production
Net to the Company
Year Ended March 31, 2008

	Quarter Ended			
	June 30, 2007	September 30, 2007	December 31, 2007	March 31, 2008
India				
Oil (bbls/d)	271	202	207	195
NGL (bbls/d)	6	-	-	1
Gas (Mcf/d)	34,736	33,347	29,688	26,878
Mcfe/d – India	36,397	34,557	30,932	28,057
Bangladesh				
NGL (bbls/d)	57	57	52	59
Gas (Mcf/d)	49,762	52,276	45,637	51,650
Mcfe/d – Bangladesh	50,105	52,618	45,951	52,003
Mcfe/d – Total	86,502	87,175	76,883	80,060

Netback History – India[1]
Natural Gas
Year Ended March 31, 2008
Quarter Ended

	Quarter Ended			
	June 30, 2007	September 30, 2007	December 31, 2007	March 31, 2008
Average Price Received ($/Mcf)	4.67	4.53	4.26	4.49
Royalties ($/Mcf)[1]	(0.42)	(0.41)	(0.39)	(0.41)
Profit Petroleum ($/Mcf)[1]	(1.56)	(0.67)	(0.43)	(0.57)
Production Costs ($/Mcf)	(0.56)	(0.50)	(0.53)	(0.52)
Netback ($/Mcf)	2.13	2.95	2.91	2.99

Netback History – Bangladesh[1]
Natural Gas
Year Ended March 31, 2008
Quarter Ended

	Quarter Ended			
	June 30, 2007	September 30, 2007	December 31, 2007	March 31, 2008
Average Price Received ($/Mcf)	2.49	2.37	2.22	2.29
Royalties ($/Mcf)[1]	-	-	-	-
Profit Petroleum ($/Mcf)[1]	(0.82)	(0.78)	(0.73)	(0.77)
Production Costs ($/Mcf)	(0.29)	(0.19)	(0.27)	(0.16)
Netback ($/Mcf)[2]	1.38	1.40	1.22	1.36

Netback History – India[1]
Oil and Condensate
Year Ended March 31, 2008
Quarter Ended

	Quarter Ended			
	June 30, 2007	September 30, 2007	December 31, 2007	March 31, 2008
Average Price Received ($/bbl)	53.55	61.86	76.27	103.81
Royalties ($/bbl)[1]	(5.28)	(5.06)	(4.94)	(5.25)
Profit Petroleum ($/bbl)[1]	(25.33)	(23.28)	(12.62)	(18.79)
Production Costs ($/bbl)	(5.03)	(5.27)	(5.38)	(6.88)
Netback ($/bbl)	17.91	28.25	53.33	72.89

Netback History – Bangladesh
Oil and Condensate
Year Ended March 31, 2008
Quarter Ended

	Quarter Ended			
	June 30, 2007	September 30, 2007	December 31, 2007	March 31, 2008
Average Price Received ($/bbl)	75.84	77.19	84.83	98.41
Royalties ($/bbl)[1]	-	-	-	-
Profit Petroleum ($/bbl)[1]	(26.65)	(27.11)	(30.52)	(21.78)
Production Costs ($/bbl)	(1.71)	(1.16)	(1.48)	(0.90)
Netback ($/bbl)[2]	47.48	48.92	52.83	75.73

Notes:

(1) Under the terms of the gas sales contracts that are in place with respect to Niko's natural gas production from its India properties, the purchasers of the natural gas pay the royalties and sales taxes levied by the GOI as well as transportation charges over and above the contracted price. Under the terms of the applicable PSCs, the governments of India and Bangladesh are entitled to a percentage share of the profit gas produced, which percentage is based upon the multiple of investment cost recovery by Niko. See "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Disclosure – India" and "Statement of Reserves Data and other Oil and Gas Information – Disclosure of Reserves Data – Reserves Disclosure – Bangladesh". There are no royalties or sales tax levied by the Government of Bangladesh related to Bangladesh production.

(2) The netbacks related to Bangladesh are calculated based on amounts recorded in the Company's financial statements for Fiscal 2008, however, the Company has not been paid for production from the Feni field in Bangladesh for Fiscal 2008.

The following table sets forth the net production by area for the Company's Hazira and Surat properties as at March 31, 2008 in India and the Company's Block 9 and Feni properties in Bangladesh being the only properties from which there was commercial production during that time.

Area	Light and Medium Oil bbls/d	Gas Mcf/d	NGL bbls/d	Total Natural Gas Equivalent Mcfe/d
Hazira	219	21,848	1	23,171
Surat	-	9,316	-	9,316
India Total	219	31,164	1	32,487
Block 9	-	44,606	51	44,913
Feni	-	5,221	5	5,251
Bangladesh Total	-	49,827	56	50,164
Company Total[1]	219	80,991	57	82,651

Note:

(1) The Company total excludes the production relating to Canada as they comprise less than 0.02% of the Company's total reserves.

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

In the tables set forth in "Statement of Reserves Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form, unless otherwise indicated, the following definitions and other notes are applicable.

- "**Gross**" means:

  (a) in relation to the Company's interest in production and reserves, its "gross revenues", which are the Company's interest (operating and non-operating) share before deduction of royalties and profit petroleum without including any royalty interest of the Company;

  (b) in relation to wells, the total number of wells in which the Company has an interest; and

  (c) in relation to properties, the total area of properties in which the Company has an interest.

- "**Net**" means:

  (a) in relation to the Company's interest in production and reserves are the Company's interest (operating and non-operating) share after deduction of royalty obligations and profit petroleum, plus the Company's royalty interest in production or reserves;

  (b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells;

  (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company; and

  (d) in relation to the Company's capital expenditures or forecast capital expenditures for a property, the total expenditure for the property in which the Company has an interest multiplied by the working interest owned by the Company.

- Definitions of Reserves:

  Reserve Categories

  Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

  - analysis of drilling, geological, geophysical and engineering data;
  - the use of established technology; and
  - specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

  Reserves are classified according to the degree of certainty associated with the estimates.

  (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The quantitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- At least a 50% probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

- Future Income Tax Expense

  Future income tax expenses are estimated:

  (c) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes between oil and gas activities and other business activities;

  (d) without deducting estimated future costs that are not deductible in computing taxable income;

  (e) taking into account estimated tax credits and allowances; and

  (f) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

- "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic location horizon known to be productive.

- "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

  (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

  (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

  (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

  (d) provide improved recovery systems.

- "**Exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

- "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

  (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

- "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

- Numbers may not add due to rounding.

- The estimates of future net revenue presented do not represent fair market value.

- Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

- Estimated future abandonment and reclamation costs related to a property have been taken into account by Ryder Scott in determining reserves that should be attributable to a property and, in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

- The forecast price and cost assumptions assume the continuance of current laws and regulations.

- The extended character of all factual data supplied to Ryder Scott were accepted by them as represented. No field inspection was conducted.

MANAGEMENT OF NIKO

The name, province and country of residence and principal occupation of each of the directors and senior officers of Niko are as follows:

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years[1]
Edward S. Sampson[9] Alberta, Canada	President and Chief Executive Officer of the Company since November 2004. Also Chairman of the Board of the Company for in excess of the last 12 years.	Chairman of the Board, President and Chief Executive Officer
Conrad P. Kathol[3][4][9] Alberta, Canada	Director	President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004. Prior thereto, President of Invader Exploration Inc. (a public oil and gas company).

Name and Residence	Positions Held With Niko[7][8]	Principal Occupation During Last Five Years[1]
Wendell W. Robinson[2][3] South Carolina, U.S.A.	Director	Senior Investment Partner & retired Managing Director, Global Environment Fund (an institutional investment management firm) since February 2006. Prior thereto, Managing Director, Global Environment Fund.
Walter DeBoni[2][4][5] Alberta, Canada	Director	Vice President of Canada Frontier & International Business of Husky Energy Inc. (a public oil and gas company) from April 2002 to July 2005. Prior thereto, President and Chief Executive Officer, Bow Valley Energy Ltd. (a public oil and gas company) until January 2002.
C. J. (Jim) Cummings[2][3][5] Alberta, Canada	Director	Partner of International Energy Counsel LLP (a law firm) since December 2002. Prior thereto, Partner of Donahue LLP (a law firm) until November 2002.
William T. Hornaday[4][5] Alberta, Canada	Chief Operating Officer, Director	Chief Operating Officer of Niko Resources Ltd. Since 2005. Prior thereto, Vice President, Operations of Niko since 2001.
Murray E. Hesje Alberta, Canada	Chief Financial Officer, VP Finance	VP Finance and Chief Financial Officer of Niko since 2006. From 2004 to 2006 Chief Operating Officer of Pearl Energy Limited (a natural resources company). Prior thereto Vice President Finance at Gulf Canada limited (a natural resource company).

Notes:

(1) Each of the above persons has held the principal position shown opposite his name for the last five years, unless otherwise noted.

(2) Mr. Robinson is the chairman, and Mr. Cummings and Mr. DeBoni are members, of the Audit Committee.

(3) Mr. Robinson is the chairman, and Mr. Cummings and Mr. Kathol are members, of the Compensation Committee.

(4) Mr. Kathol is the chairman, and Mr. DeBoni and Mr. Hornaday are members, of the Environment and Reserve Committee.

(5) Mr. Cummings is the chairman, and Mr. DeBoni and Mr. Hornaday are members, of the Corporate Governance Committee.

(6) The Company does not have an executive committee.

(7) The following individuals were initially appointed or elected directors of Niko in the following years: Messrs. Sampson and Kathol (1996), Mr. Robinson (1999), Messrs. Cummings and DeBoni (2005) and Mr. Hornaday (2007).

(8) The directors will hold office until the next annual meeting of holders of Common Shares or until their successor is duly elected or appointed, unless their office is earlier vacated in accordance with the Company's By-Laws.

(9) Conrad P. Kathol, a director of Niko, and Edward S. Sampson, an officer and a director of Niko, were both directors, but not officers, of Proprietary Industries Inc. ("**Proprietary**") during a period for which the Alberta Securities Commission (the "**ASC**")

was investigating Proprietary. Proprietary is a public corporation organized under the *Canada Business Corporations Act*. Niko was, at the time of the transactions referred to below, arm's length to Proprietary and the other public companies referred to below and Niko has never had business dealings with Proprietary and such public companies. In January of 2002, a notice of hearing was issued by the ASC with respect to Proprietary and two of its senior officers, Peter Workum and Theodor Hennig, alleging that (i) Proprietary's consolidated financial statements for the years ended September 30, 2000, September 30, 1999 and September 30, 1998 were not prepared in accordance with generally accepted accounting principles and contained misrepresentations contrary to the *Securities Act* (Alberta) with respect to gains reported in connection with certain transactions involving Proprietary, and (ii) Proprietary made representations in respect of material submitted or given to the ASC in connection with those transactions contrary to the *Securities Act* (Alberta). On August 21, 2002, the ASC issued an order (a) cease trading all trades in securities of Proprietary and all trades of Messrs. Workum and Hennig and certain subsidiaries of Proprietary and (b) denying Proprietary, Messrs. Workum and Hennig and such subsidiaries the use of any exemptions from the prospectus and registration requirements under the *Securities Act* (Alberta) for a period of 15 days. On September 5, 2002, the ASC issued a further order extending the earlier interim order. Securities regulatory authorities in other provinces in Canada issued similar orders with respect to Proprietary. Mr. Sampson resigned as a director of Proprietary in March of 2001 and Mr. Kathol resigned as a director of Proprietary on December 18, 2002. In August 2003, the ASC staff and Proprietary entered into a settlement agreement whereunder Proprietary acknowledged, among other things, that certain recognitions of gains contained in its audited consolidated financial statements for its Fiscal years ended September 30, 1998, 1999 and 2000 were contrary to generally accepted accounting principles and agreed to pay $125,000 to the ASC in partial satisfaction of the ASC's costs. On November 21, 2003 the ASC issued an order lifting the sanctions referred to in (a) and (b) above as they related to Proprietary. However, in November and December of 2003, the ASC issued a further cease trade order against Proprietary for failure to file annual audited financial statements for its Fiscal year ended September 30, 2002. This cease trade order was subsequently lifted on May 6, 2004 and trading of Proprietary's shares on the Toronto Stock Exchange resumed on May 19, 2004.

As at June 24, 2008, the directors and executive officers of Niko, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 6,805,499 Common Shares constituting approximately 13.8% of the issued and outstanding Common Shares. Of these shares, 2,376,229 are shares over which Mr. Ed Sampson has control or direction as executor of the estate of Robert N. Ohlson, the former President of the Company.

Orders

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Company), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control thereof, (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties and Sanctions

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer or shareholder holding a sufficient number of Common Shares to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

AUDIT COMMITTEE

The purpose of Niko's audit committee is to provide assistance to the board of directors of Niko in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Company and its subsidiaries. It is the objective of the audit committee to maintain a free and open means of communications among the board of directors of Niko, the independent auditors and the financial and senior management of the Company.

The full text of the Audit Committee's charter is included as Schedule A to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of C. J. (Jim) Cummings, Walter DeBoni and Wendell W. Robinson. The Audit Committee Charter is attached as Schedule A to this Annual Information Form. Wendell W. Robinson is the Chairman of the Audit Committee. Each of the members is financially literate under section 1.6 of MI 52-110 and each of the members is independent under section 1.4 of MI 52-110.

Relevant Education and Experience

C. J. (Jim) Cummings has been involved in the petroleum industry in excess of the past 30 years. He graduated from the University of Alberta with a degree in Law and has practiced in government, corporate and private roles, specializing in international oil and gas law. Mr. Cummings has served as Senior Counsel with the Attorney General of Alberta in the Constitutional and Energy Law Department, Senior Counsel with Home Oil Company Limited, Vice-President and General Counsel with both Asamera Inc. and Bow Valley Energy Ltd. and was formerly a partner in Donahue LLP. He is currently a partner in International Energy Counsel LLP and a director of a number of private corporations. He is a past Chair of the Association of General Counsel of Alberta and is a past member of the Steering Committee of the Canadian Chapter of the Association of International Petroleum Negotiators.

Walter DeBoni has held numerous top executive posts in the oil and gas industry. He holds a Bachelor of Science (B.Sc.) in Chemical Engineering from the University of British Columbia and an MBA degree with a major in Finance from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers of the Canadian Institute of Mining, Metallurgy and Petroleum (CIM). He is past Chairman of the Petroleum Society of CIM and a past director of the Society of Petroleum Engineers.

Wendell Robinson joined Global Environment Fund as Managing Director from Rockefeller & Co. where he was responsible for Rockefeller's worldwide private equity program. For various funds, Mr. Robinson has managed the investment and successful sale of more than $450 million in private equity and venture capital positions throughout Southeast Asia, Europe, Latin America and the United States. Mr. Robinson has been a director of numerous corporations, as well as a member of investment advisory boards and investment committees for private investment funds and partnerships in Argentina, Brazil, China, Spain, France and the United States. Mr. Robinson has in excess of 40 years of experience in domestic and international financial, investment and company management. Mr. Robinson holds a Bachelor of Business Administration (BBA) and Masters of Business Administration (MBA) in finance and economics and is a Chartered Financial Analyst (CFA) of the International Society of Chartered Financial Analysts.

Audit Committee Oversight

All recommendations of the Audit Committee in respect of the nomination and compensation of external auditors have been adopted by the Board.

Pre-Approval Policies and Procedures

The Audit Committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence. See section 5.2.9 of the audit committee charter attached as Schedule A to this Annual Information Form.

Audit Fees

The aggregate fees billed by the Company's external auditor for audit services including quarterly reviews for Fiscal 2008 were $556,300 ($434,000 – Fiscal 2007).

Audit-related Fees

The aggregate fees billed by the Company's external auditor for professional services with respect to prospectuses, translation of foreign language financial statements and audit certifications for Fiscal 2008 were $105,400 ($121,700 – Fiscal 2007).

Tax Fees

The aggregate fees billed by the Company's external auditor for professional services including tax compliance, tax advice and tax planning in Fiscal 2008 were $123,700 ($110,900 – Fiscal 2007).

All Other Fees

There were no other fees billed during Fiscal 2007 or Fiscal 2008 by the company's external auditors.

CONFLICTS OF INTEREST

Certain directors and officers of Niko and its subsidiaries are associated with other reporting issuers or other corporations, which may give rise to conflicts of interest. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships or other business relationships which may create situations in which conflicts may arise. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Niko are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Niko. Certain of the directors of Niko have either other employment or other business or time restrictions placed on them and, accordingly, these directors will only be able to devote part of their time to the affairs of Niko.

EXPERTS

The audited financial statements of Niko for Fiscal 2008 were audited by KPMG LLP, Chartered Accountants, of Calgary, Alberta.

Ryder Scott prepared the Ryder Scott Report with respect to the Company's reserves in D6, Hazira Field, Surat Block, the Feni field and Block 9. See "Statement of Reserves Data and Other Oil and Gas Information". Ryder Scott also signed the Report on Reserves Data by Independent Qualified Reserves Evaluators – Form 51-102F2 contained elsewhere in this Annual Information Form.

As far as Niko is aware, as of the date hereof, the partners and associates of KPMG LLP did not beneficially own any outstanding Common Shares. KPMG is independent in accordance with the rules of professional conduct outlined by the Institute of Chartered Accountants of Alberta. As far as Niko is aware, as at the date hereof, the principals of Ryder Scott did not beneficially own any outstanding Common Shares.

DIVIDENDS

In June 2001, the Company implemented a policy of paying quarterly dividends on the Common Shares. Since that time, the Company has declared and paid a quarterly dividend of $0.03 per Common Share for each successive quarter. The facility agreement of the Company restricts the Company's ability to pay dividends prior to the completion of the D6 gas development project to CDN$0.03 per share in any quarter provided that the aggregate amount of all distributions made by Niko Resources Ltd. from March 31, 2007 to the completion of the D6 gas development project is less than $15,000,000 and the Company is in compliance with a number of financial and other tests. While the Company intends to pursue a policy of paying quarterly dividends, the level of future dividends will be determined by the board of directors of the Company in light of earnings from operations, capital requirements, the financial condition of the Company and the restrictions of the facility agreement.

CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As of June 24, 2008, the Company had issued and outstanding 49,172,033 Common Shares and no other shares of any class. As of June 24, 2008, the Company had 3,253,350 options to purchase Common Shares outstanding.

The Common Shares have the following rights, privileges, restrictions and conditions:

(a) the right to receive notice of and to attend and vote at all meetings of holders of Common Shares except meetings of the holders of another class of shares, with each Common Share entitling the holder thereof to one vote;

(b) subject to the preferences accorded to the holders of the preferred shares, the holders of Common Shares are entitled to receive such dividends as may be deemed thereon by the board of directors of Niko from time to time; and

(c) in the event of the liquidation, dissolution or winding up of Niko, whether voluntary or involuntary, the holders of Common Shares are entitled to receive pro rata all of the assets remaining for distribution after the payment to the holders of the preferred shares, in accordance with the preference on liquidation, dissolution or winding-up accorded to the holders of the preferred shares.

The preferred shares have the following rights, privileges, restrictions and conditions:

(a) the board of directors of Niko may issue the preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors;

(b) the board of directors of Niko may fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including (a) the amount, if any, specified as being payable preferentially to such series on a distribution of capital of Niko, (b) the extent, if any, of further participation in a distribution of capital, (c) voting rights, if any, and

(d) dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any;

(c) in the event of the liquidation, dissolution or winding-up of Niko, whether voluntary or involuntary, the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, on a distribution of capital, to be paid rateably with the holders of each other series of preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a distribution of capital of Niko; and

(d) the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, with respect to the payment of cumulative dividends, to be paid rateably with the holders of each other series of preferred shares, the amount of cumulative dividends, if any, specified as being payable preferentially to the holders of such series.

MARKET FOR COMMON SHARES

The Common Shares have been listed and posted for trading on the TSX since December 11, 1998, under the trading symbol "NKO". The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSX for the periods indicated:

	Trade Price		**Volume Traded**
	High	**Low**	**# of shares**
April 2007	90.24	79.90	3,051,186
May 2007	98.84	87.08	2,650,370
June 2007	100.85	92.86	2,618,558
July 2007	110.24	94.90	3,854,643
August 2007	96.70	77.01	3,363,939
September 2007	98.27	89.57	2,115,956
October 2007	108.50	96.40	2,670,767
November 2007	108.27	85.38	2,681,331
December 2007	93.21	81.89	1,903,829
January 2008	92.99	73.72	3,045,440
February 2008	94.47	83.48	2,379,886
March 2008	93.00	80.70	1,943,664

PRIOR SALES

From April 1, 2007 through March 31, 2008, a total of 838,563 options to purchase Common Shares were granted to directors, officers and employees of the Company with the following exercise prices:

Number of Options Granted	Exercise Price
1,000	$80.98 per share
500	$82.31 per share
5,000	$82.83 per share
7,000	$84.00 per share
1,250	$87.61 per share
1,000	$87.88 per share
321,313	$89.99 per share
35,250	$90.40 per share
10,000	$92.17 per share
750	$92.52 per share
374,000	$93.00 per share
2,000	$96.03 per share
6,000	$96.50 per share
7,500	$97.21 per share
12,000	$97.25 per share
1,000	$97.87 per share
51,250	$99.00 per share
750	$105.00 per share
1,000	$105.47 per share

From April 1, 2007 through March 31, 2008, a total of 1,297,588 Common Shares were issued as a result of stock option exercises by the Company at the following issue prices:

Issuance of Common Shares	Issue Price
926,250	$22.20 per share
10,000	$25.20 per share
2,500	$26.47 per share
2,900	$27.85 per share
22,500	$37.45 per share
3,750	$38.36 per share
10,000	$49.30 per share
310,938	$53.70 per share
750	$61.60 per share
6,250	$63.00per share
1,750	$82.70 per share

In addition, 4,762,000 Common Shares were issued in an equity financing at a price of $105.00 per Common Share. In addition, from April 1, 2007 through March 31, 2008, a total of 74,500 options to purchase Common Shares were forfeited by directors, officers and employees of the Company.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as indicated below, to the knowledge of the directors and officers of the Company, no director or executive officer, person or company that beneficially owns or exercises control or direction over Common Shares carrying more than 10% of the voting rights attached to any class of voting shares of the Company or any associate or affiliate of the foregoing has had any material interest, director or indirect, in any transactions within the three most recently completed fiscal years or during the current fiscal year that has materially affected or will materially affect the Company.

Mr. Ed Sampson, President, Chief Executive Officer and Chairman of the Board of the Company, is executor of the estate of Robert N. Ohlson, the former President of the Company, who passed away in November of 2004. In his capacity as executor, Mr. Sampson has control or direction over 2,376,229 Common Shares held by the estate of Mr. Ohlson.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares is Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario.

LEGAL PROCEEDINGS

Other than as disclosed under "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh – Chattak and Feni Gas Fields, Bangladesh", to the knowledge of management of the Company, there are no material legal proceedings to which the Company or to which any of their property is the subject, nor are any such proceedings that are contemplated.

SHAREHOLDER RIGHTS PLAN

At the Annual and Special Meeting of the holders of Common Shares held on September 15, 1999, the holders of the Common Shares approved the Company's shareholder rights plan, the terms and conditions of which are set out in the Shareholder Rights Plan Agreement (the "**Original Rights Plan**") dated as of August 9, 1999 between the Company and Montreal Trust Company of Canada, which agreement was approved by the board of directors of the Company. At the Annual and Special Meeting of the holders of Common Shares held on September 19, 2002, the continued existence of the Original Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the Original Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2002 Rights Plan**") was executed. At the Annual and Special Meeting of the holders of Common Shares held on August 17, 2005, the continued existence of the 2002 Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the 2002 Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2005 Rights Plan**") was executed. Its continued existence must be approved and reconfirmed by the Independent Shareholders (as defined in the 2005 Rights Plan) on or before the termination of the annual meeting of the shareholders of the Company held in the year 2008.

The following is a summary description of the general operation of the 2005 Rights Plan. This summary is qualified in its entirety by reference to the text of the 2005 Rights Plan, a copy of which can be obtained by shareholders from the Company. Capitalized terms used below but not defined below have the meanings ascribed to them in the 2005 Rights Plan.

<u>Effective Date:</u> The 2005 Rights Plan is effective as of the close of business on August 9, 1999 (the "**Plan Effective Date**").

<u>Term:</u> The 2005 Rights Plan will expire at the termination of the annual meeting of Shareholders in the year 2008. If the 2005 Rights Plan is reconfirmed by the holders of Common Shares at the annual meeting of Shareholders held in the year 2008, it will expire at the termination of the annual meeting of Shareholders in the year 2011.

<u>Issue of Rights:</u> At 5:00 p.m. (Calgary time) on August 9, 1999, one Right was issued and attached to each outstanding Common share and one Right will be issued and attach to any Common share that is subsequently issued.

<u>Rights Exercise Privilege:</u> The Rights will separate from the Common Shares and will be exercisable 10 Trading Days (the "**Separation Time**") after a person has acquired, or commences a take-over bid to acquire, 20% or more of the Common Shares, other than by an acquisition pursuant to a take-over bid permitted by the 2005 Rights Plan (a "**Permitted Bid**"). The acquisition by any person (an "**Acquiring Person**") of 20% or more of the Common shares, other than by way of a Permitted Bid or Competing Permitted Bid, is referred to as a "**Flip-in Event**". Any Rights held by an Acquiring Person will become void upon the occurrence of a Flip-in Event. Ten Trading Days after the occurrence of the Flip-in Event, each Right (other than those held by the Acquiring Person) will permit the purchase of $200 worth of Common shares for $100.

The issue of the Rights is not initially dilutive. Upon a Flip-in Event occurring and the Rights separating from the Common Shares, reported earnings per share on a fully diluted or non-diluted basis may be affected. Holders of Rights not exercising their Rights upon the occurrence of a Flip-in Event may suffer substantial dilution.

Lock-Up Agreements: A person making a take-over bid may enter into lock-up agreements ("**Lock-up Agreements**") with holders of Common Shares whereby such holders agree to tender their Common Shares to the bid without a Flip-in Event occurring. The Lock-up Agreement must, among other things, permit the holders to withdraw their Common Shares and tender them to another, or to support another, take-over bid transaction that will provide greater value to such holder.

Certificates and Transferability: Prior to the Separation Time, the Rights are evidenced by a legend imprinted on certificates for the Common Shares issued from and after the Plan Effective Date and are not to be transferable separately from the Common Shares. From and after the Separation Time, the Rights will be evidenced by Rights Certificates which will be transferable and traded separately from the Common Shares.

Permitted Bid Requirements: The requirements for a Permitted Bid include the following:

1. the take-over bid must be made by way of a take-over bid circular;

2. the take-over bid must be made to all shareholders, wherever resident;

3. the take-over bid must be outstanding for a minimum period of 45 days and Common Shares tendered pursuant to the take-over bid may not be taken up prior to the expiry of the 45-day period and only if at such time more than 50% of the Common Shares held by Independent Shareholders have been tendered to the take-over bid and not withdrawn; and

4. if more than 50% of the Common Shares held by Independent Shareholders are tendered to the take-over bid within the 45-day period, the bidder must make a public announcement of that fact and the take-over bid must remain open for deposits of Common Shares for not less than 10 Business Days from the date of such public announcement.

The 2005 Rights Plan allows for a competing Permitted Bid (a "**Competing Permitted Bid**") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all the requirements of a Permitted Bid except that it may expire on the same date as the Permitted Bid, subject to the requirement that it be outstanding for the minimum deposit period under Canadian securities laws (currently 35 days).

Waiver: The board of directors of the Company, acting in good faith, may, until the occurrence of a Flip-in Event, waive the application of the Rights Plan to a particular Flip-in Event (an "**Exempt Acquisition**") where the take-over bid is made by a take-over bid circular to all holders of Common Shares. Where the board of directors exercises the waiver power for one take-over bid, the waiver will also apply to any other take-over bid for the Company made by take-over bid circular to all holders of Common Shares prior to the expiry of any other bid for which the 2005 Rights Plan has been waived.

Redemption: The board of directors of the Company, with the majority approval of shareholders (or the holders of Rights if the Separation Time has occurred) at a meeting duly called for that purpose, may redeem the Rights at $0.0001 per Right. Rights may also be redeemed by the board of directors on behalf of the Company without such approval following completion of a Permitted Bid, Competing Permitted Bid or Exempt Acquisition.

Amendment: The board of directors of the Company may amend the 2005 Rights Plan with the majority approval of shareholders (or the holders of Rights, if the Separation Time has occurred) at a meeting duly called for that purpose. The board of directors without such approval may correct clerical or typographical errors and, subject to approval as noted above at the next meeting of the shareholders (or holders of Rights, as the case may be), may make amendments to the 2005 Rights Plan to maintain its validity due to changes in applicable legislation.

<u>Exemptions for Investment Advisors:</u> Investment advisors (for fully managed accounts), trust companies (acting in their capacities as trustees and administrators), statutory bodies whose business includes the management of funds and administrators of registered pension plans acquiring greater than 20% of the Common Shares are exempted from triggering a Flip-in Event, provided that they are not making, or are not part of a group making, a take-over bid for the Company.

<u>Board of Directors:</u> The 2005 Rights Plan will not detract from or lessen the duty of the board of directors of the Company to act honestly and in good faith with a view to the best interests of the Company. The board of directors, when a Permitted Bid is made, will continue to have the duty and power to take such actions and make such recommendations to shareholders as are considered appropriate.

RISK FACTORS

An investment in Niko should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas in foreign countries and its current stage of development. Oil and gas operations involve many risks and uncertainties, which even a combination of experience and knowledge and careful evaluation, may not be able to overcome. Additional risks and uncertainties not currently known to the management of Niko may also have an adverse effect on Niko's business and the information set out below does not purport to be an exhaustive summary of the risks affecting Niko.

There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company. Exploration, appraisal and development of oil and gas reserves is speculative and involve a significant degree of risk. There is no guarantee that exploration or appraisal of the properties in which Niko holds an interest will lead to a commercial discovery or, if there is a commercial discovery, that Niko will be able to realize such reserves as intended. Few properties that are explored are ultimately developed into new reserves. If at any stage Niko is precluded from pursuing its exploration or development programs, or such programs are otherwise not continued, Niko's business, financial conditions and/or results of operations and accordingly, the trading price of its common shares, is likely to be materially affected.

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, revolution, border disputes, expropriation, renegotiations or modification of existing contracts, freezing of bank accounts and other assets, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labour disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Niko operates may make sudden changes in laws relating to taxation or impose higher tax rates which may affect Niko's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Niko believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Niko. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Niko which can result in Niko having to pay significant penalties and fines. The Company's international operations may also be adversely affected by laws and policies of the United States and Canada affecting foreign trade, taxation and investment. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

Exploration and development activities may be delayed or adversely affected by factors outside the control of Niko. These include adverse climate and geographic conditions, including offshore operations, labour disputes, the performance of joint venture or farm-in partners on whom Niko may be or may become reliant, compliance with governmental requirements, shortages or delays in installing and commissioning plant and equipment or import or customs delays. Problems may also arise due to the quality or failure of locally obtained equipment or interruptions to services (such as power, water, fuel or transport or processing capacity) or technical support which result in failure to achieve expected target dates for exploration or production and/or result in a requirement for greater expenditure. Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells that, though yielding some oil or gas, are not sufficiently productive to justify commercial development or cover operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

The marketability of oil and natural gas acquired or discovered in the countries in which the Company operates will be affected by numerous factors beyond the control of the Company. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. The Company's oil and natural gas operations may also be subject to compliance with laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue, causing a reduction in its oil and gas acquisition and development activities.

Infrastructure development in many of the countries in which the Company operates is limited. These factors may affect the Company's ability to explore and develop its properties and to store and transport its oil and gas production. There can be no assurance that future instability in one or more of the countries in which Niko operates, actions by companies doing business there, or actions taken by the international community will not have a material adverse effect on the countries in question and in turn on the Company's financial conditions or operations.

There are numerous uncertainties inherent in estimating quantities of reserves and the present value of net cash flows attributable to such reserves. Such estimates represent subjective judgements based on available data and the quality of such data. Different reserve engineers may make different estimates of reserve quantities and the present value of net cash flows attributable to the production of such quantities. Substantial revisions to the reserve quantities and present value estimates may be necessary due to numerous factors, including the results of drilling, testing and production and changes in the assumptions regarding decline and production rates, taxes, royalties, prices and costs made after the date of a reserve estimate. The reserve estimates included and incorporated by reference in this document could be materially different from the quantities and values ultimately realised.

The Company is dependent on receipt of government approvals or permits or no objection certificates to develop its properties. Any change in government or legislation or delays in receiving government approvals or permits or no objection certificates may delay the development of the Company's properties or may affect the status of the Company's contractual arrangements or its ability to meet its contractual obligations.

Based on the Company's forecasted cash and capital requirements over Fiscal 2009, the Company expects that its funds from operations, credit facility and cash on hand will be sufficient to meet all of its working capital requirements and planned capital expenditures in Fiscal 2009, however, there is a risk that the Company will not have sufficient funds to meet planned capital expenditures. The Company's ability to raise financing in the future is subject to market or commodity price changes, economic downturns and the future performance of the Company. There can be no assurances that any required financing will be available to Niko when needed or even if it is available, that it will be available on terms that are acceptable to Niko. If such financing is not available or is not available on terms that are acceptable to Niko, this could impact Niko's ability to carry out its planned exploration and/or development activities and/or its ability to comply with contractual obligations it has under the agreements governing its properties or under its agreements with its various partners which could result in loss of rights under such agreements, legal action against Niko and/or loss of properties, any of which could have a substantial negative impact on Niko and its financial position. Any additional issuance of Common Shares by Niko will result in dilution to its current holders of Common Shares, which dilution could be substantial.

From time to time, the Company may enter into work commitments on new or existing fields or blocks or into transactions to acquire assets or the shares of other companies. These activities may be financed partially or wholly with equity or with debt, the latter of which could increase the Company's debt levels above industry standards. Depending on future exploration and development plans and results thereof, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms.

The Company expects the commencement of production from the D6 Dhirubhai 1 and 3 gas fields and MA oil field in the third calendar quarter of 2008. There are a number of factors that could contribute to a delay in start-up including weather conditions, construction resource availability, delay in deliveries of goods from vendors, non-availability of drilling rigs, fishermen activities surrounding vessels/rigs, installation delays, completion and safe transport of FPSO and inability to sign gas contracts.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas in which such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators to comply with the terms of the agreements granting the interests in its properties and for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

The Company is currently prevented from drawing further amounts from the credit facility because the Company is unable to meet one of the conditions precedent to borrowing funds. The Company expects that this condition precedent will be fulfilled once the lenders have adopted projections based on the March 31, 2008 reserve reports and subsequently, the Company expects to be able to borrow additional funds. There is a risk that the condition precedent will not be lifted or that the Company will not be able to draw further amounts of long-term debt. There are a number of qualitative and quantitative factors in the facility agreement that prevent the Company from borrowing additional funds and which could trigger an early repayment.

Repayment of the outstanding debt amounts is based on certain financial ratios as determined in accordance with the agreement, with the outstanding debt amount not to exceed a reduction schedule. The financial ratios are based on the future cash flows from producing properties determined in accordance with the agreement. Failure to meet these ratios will trigger early payment of a part or the entire long-term debt balance. There are a number of other items in the agreement that could trigger early payment of a part of the entire balance of long-term debt including, but not limited to: the inability of the Company to complete project completion as defined in the agreement prior to a specified date; the Company not having sufficient funds to complete the project; the Company not having gas sales contract for a quantity sufficient to support future cash flows required to meet the financial ratios and compliance with various information and other requirements specified in the agreement.

During the year ended March 31, 2006, Niko Resources (Bangladesh) Ltd. received a letter from the 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 368,500,000 (Cdn$5.3 million) for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas; (ii) Taka 723,500,000 (Cdn$10.4 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 (Cdn$12.1 million) for environmental damages, an amount subject to be increased upon further assessment; (iv) Taka 5,527,500,000 (Cdn$79.4 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and (v) any other claims that arise from time to time. The Company and the Government of Bangladesh had previously agreed to settle the government's claims through arbitration conducted in Bangladesh based upon international rules. The

Company will actively defend itself against the lawsuit. This process could take in excess of three years. There is a risk that the Company will lose the lawsuit in the Bangladesh low courts. Any negative result to the Company and its subsidiary with respect to the above could have an adverse impact on the Company and its financial position.

Some of the jurisdictions in which Niko operates may have less developed legal systems than jurisdictions with more established economies which may result in risks such as (i) effective legal redress in the courts of such jurisdictions, whether in respect of breach of law or regulation or in an ownership dispute, being more difficult to obtain, (ii) a higher degree of discretion on the part of governmental authorities, (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (v) relative inexperience of the judiciary and courts in such matters. There can be no assurance that joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities or other third parties and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, pollution, seepage or leaks, earthquake activity and unusual or unexpected geological conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers adequate, the nature of these risks is such that liabilities could exceed policy limits or such insurance may not cover the consequences of such events. In addition, certain risks may be such that the Company may choose, because of the high cost of premiums, to elect not to insure against such risks. In any of these circumstances, the Company could incur significant costs that could have a materially adverse effect upon its financial condition.

During Fiscal 2006, a group of petitioners in Bangladesh filed a writ with the Supreme Court of Bangladesh against various parties, including NRBL. The petitioners are requesting the following of the Supreme Court of Bangladesh (Supreme Court) with respect to the Company: (i) that the Joint Venture Agreement for the Feni and Chattak fields be declared null and illegal, (ii) 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, (iii) that Petrobangla withhold future payments owing to the Company relating to production from the Feni field (US$25.3 million owing and unpaid as at March 31, 2008), and (iv) that all bank accounts of the Company maintained in Bangladesh be frozen. At one point during Fiscal 2006, an order was issued by the Supreme Court in this lawsuit freezing the Bangladesh bank accounts of the Company's Bangladesh subsidiary. This freeze was lifted shortly thereafter, allowing the Company's Bangladesh subsidiary to make payments to Bangladesh vendors and suppliers. However the Supreme Court has provided that payments by the Company's Bangladesh subsidiary to vendors and suppliers outside of Bangladesh are prohibited. The Company's foreign vendors are being paid from bank accounts of the Bangladesh subsidiary that are located outside the country. If this legal action is determined negatively against the Company's subsidiary in Bangladesh it could result in the cancellation of such subsidiary's interests in the Feni and Chattak fields as well as imposition of relief against such subsidiary as detailed in (ii), (iii) and (iv) above which could have a significant adverse impact on the Company and its financial position. Also, there can be no guarantee that the Supreme Court will not place a freeze on the bank accounts in the future and if it does, that such freeze can be lifted in a timely manner or at all.

Approximately 41% of the Company's total revenue in Fiscal 2008 was derived from natural gas production from the Hazira Field in India and approximately 39% of the Company's total revenue in Fiscal 2008 was derived from natural gas production from the Block 9 Field in Bangladesh. The occurrence of any event that would prevent the production of natural gas by the Company from these fields, including physical problems with the infrastructure facilities (howsoever arising) supporting the field or negative actions on the part of any government or regulatory authority in India or Bangladesh, would have a significant adverse effect on the Company's cash flows and revenue until such time as such problem is remedied.

The Company has filed its income tax returns for the years 1998 through 2007 in India, under provisions that provide for a tax holiday for production from the Hazira and Surat fields. The Company received a favourable ruling with respect to the tax holiday at the third tax assessment level for the 1999 through 2004 taxation years. The Income Tax Department has filed an appeal against the order and the matter is currently pending with the Indian courts. The taxation years 2005 through 2007 have been filed including a deduction for the tax holiday, but have not yet been assessed. Should the Company fail through the legal process to receive a favourable ruling with respect to the taxation years 1999 through 2004, the Company would record a tax expense of US$39.9 million, pay additional taxes of US$10.7 million and write off US$29.2 million of the income tax receivable. There is a risk of penalties and interest on amounts assessed and the assessed amounts, the penalties and the interest may have a significant adverse effect on the Company and its financial condition.

Oil and natural gas production operations are subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations. These events may result in a significant decrease in the cash flows of the Company and the Company's financial condition.

Failure to comply with applicable laws, regulations and permit requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions. Parties engaged in oil and gas operations may be required to compensate those suffering loss or damage by reason of such activities and may have civil or criminal fines or penalties imposed.

The petroleum industry, in all countries in which the Company operates, is competitive in all its phases. The Company competes with numerous other participants in the search for and the acquisition of oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil companies which have greater financial resources, staff and facilities than those of the Company. The Company's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploration and development. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

The Company and GSPC submit annual expenditure budgets to the GOI for approval for all their Indian fields and blocks. Expenditures in excess of the budget are subject to approval by the GOI. The Company has compiled cost over-runs for prior years and is in the process of reviewing them with the GOI. If these expenditures are not ratified by the GOI, the allowable expenditure limit for any given year may be reduced and this would affect the investment multiple, potentially affecting the petroleum profit share calculation.

The Company has been delivering gas from the Feni field in Bangladesh to Petrobangla, the Government of Bangladesh state oil and gas company since November 2004. As at March 31, 2008, Petrobangla owed US$25.3 million to the Company's Bangladesh subsidiary for gas delivered to Petrobangla from the Feni field, which amount remains unpaid. In addition, Petrobangla continues to not pay for gas that is continuing to be delivered to it from the Feni field and there is a risk that Petrobangla will continue not paying for the gas supplied to it. The Company also has no assurances that Petrobangla will pay the outstanding receivable referred to above for the gas it has not yet paid for. Petrobangla is also the purchaser of the Block 9 gas.

The Company is a joint venture partner in most of its fields and may enter into further joint ventures in the future. As a result, the Company's ability to execute its business plan may be constrained by partner involvement and the action of its joint venture partners particularly where the joint venture partner is the operator and/or holds a significantly larger interest in the property than the Company.

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Company. The contributions of these personnel to the immediate operations of the Company are likely to be of central importance. In addition, competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgement, discretion, integrity and good faith of the management of the Company.

As the Company is involved in oil and gas exploration, it is subject to extensive environmental and safety legislation (for example, in relation to plugging and abandonment of wells, discharge of materials into the environment and otherwise relating to environmental protection) and this legislation may change in a manner that may require additional or stricter standards than those now in effect, a heightened degree of responsibility for companies and their directors and employees and more stringent enforcement of existing laws and regulations. There may be unforeseen environmental liabilities resulting from oil and gas activities that may be costly to remedy. In particular, the acceptable level of pollution and the potential clean-up costs and obligations and liability for toxic or hazardous substances for which the Company may become liable as a result of its activities may be impossible to assess against the current legal framework and current enforcement practices of the various jurisdictions. The extent of potential liability, if any, for the costs of abatement of environmental hazards cannot be accurately determined and consequently no assurances can be given that the costs of implementing environmental measures or meeting any liabilities in the future will not be material to the Company or affect its business or operations.

Virtually all of the Company's revenues and costs are currently denominated in foreign currency, particularly the Indian Rupee and the US dollar and the local currencies of each of the countries in which the Company operates. In addition, the facility for which the Company has signed a term sheet will be denominated in US dollars. As a result, the Company is and expects to be in the future exposed to market risks resulting from fluctuations in foreign currency exchange rates. Material fluctuations in the value of any such foreign currency as compared to the Canadian dollar could result in a material adverse effect on the Company's cash flow and revenues.

Niko and its joint venture partner in Block 9 in Bangladesh currently have a US$5.3 million bank performance guarantee provided to the Government of Bangladesh that guarantees the performance of the initial exploration obligations under the Block 9 PSC. The Block 9 Guarantee currently expires on July 15, 2009. The Government of Bangladesh has the right to collect on this guarantee if the Company does not carry out the work commitments required under the Block 9 PSC. The Government of Bangladesh may require Niko to extend the guarantee beyond the expiry date of July 15, 2009.

The Company's gas sales for Fiscal 2008 were to 12 customers: Petrobangla (43%), GGCL (17%), GSEG (11%), Essar (6%) and the remaining eight customers accounted for 23% of total sales. The Essar contract and five additional contracts were not renewed and the Company currently has six contracts for the sale of gas. The Company's sales of natural gas and therefore its revenues are currently dependent upon the remaining purchasers. The occurrence of any event that would cause any purchaser, or one of any other purchasers to which the Company commences selling natural gas production, to cease, or to materially reduce, its purchases of natural gas from the Company, could have a significant adverse effect on the Company's cash flows and revenue until such time as alternative purchasers could be arranged. The Company has not received payment from Petrobangla for the gas sales to it from the Feni field in Bangladesh in Fiscal 2008. The Company has received payment from Petrobangla for the gas sales to it from the Block 9 field in Bangladesh in Fiscal 2008. Petrobangla is also the purchaser of the Block 9 gas.

The Company is required to hire and train local workers in its petroleum operations. Some of these workers may be organized into labour unions. Any strike activity or labour unrest could adversely affect the Company's ongoing operations and its ability to explore for, produce and market its oil and gas production.

The Company and its partner are currently in arbitration with the Government of India with respect to the cost recovery status of the investment in the 36-inch pipeline at Hazira. If successful in the arbitration, the Company would reduce its profit petroleum payments currently being made. Additionally, in October 2002, GSPC and the Company signed a memorandum of understanding in which GSPC agreed to transfer the rights of the 36-inch pipeline to the joint venture. At March 31, 2008, the Company is attempting to obtain legal title to the 36-inch pipeline. Although there is a signed memorandum of understanding, there is a risk that title of the 36-inch pipeline does not transfer to the joint venture and may result in an adverse impact on the Company and its financial position.

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Conflicts of Interest".

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, is contained in the management information circular and proxy statement of the Company dated June 25, 2007 for the annual and special meeting of the holders of Common Shares. Additional financial information is also provided in the Company's financial statements and management's discussion and analysis for the year ended March 31, 2008. These documents and additional information relating to the Company can be found on SEDAR at www.sedar.com.

Copies of these documents may be obtained, in some cases upon payment of a reasonable charge, upon request to:

Niko Resources Ltd.
Suite 4600, Canterra Tower
400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2
Phone: (403) 262-1020
Fax: (403) 263-2686
Attention: President, Chief Executive Officer and Chairman of the Board

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meanings herein.

To the Board of Directors of Niko Resources Ltd. ("the Company"):

1. We have evaluated the Company's reserves data as at March 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2008, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2008, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (USD 000s))			
			Audited	**Evaluated**	**Reviewed**	**Total**
Ryder Scott Company	March 31, 2008	Bangladesh and India	N/A	$1,867,736	N/A	$1,867,736

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized accordingly to the probability of their recovery.

Executed as to our report referred to above:

Ryder Scott Company-Canada, Calgary, Alberta, Canada

Execution Date: Dated as of the 13th day of June, 2008

(signed) "Howard C. Lam"
Howard C. Lam, P. Eng.,
Managing Senior Vice President

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings is ascribed in National Instrument 51-101 have the same meanings herein.

Management of Niko Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2008, estimated using forecast prices and costs.

Independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in this Annual Information Form of the Company for the year ended March 31, 2008.

The Environment and Reserve Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation ; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Environment and Reserve Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Environment and Reserve Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Edward S. Sampson"
Edward S. Sampson
Chairman of the Board, President and Chief Executive Officer

(*signed) "William T. Hornaday"*
William T. Hornaday
Chief Operating Officer

(signed) "Walter DeBoni"
Walter DeBoni
Director

(signed) *"Conrad A. Kathol"*
Conrad A. Kathol
Director

Dated: June 23, 2008

SCHEDULE "A"
NIKO AUDIT COMMITTEE CHARTER

1.0 Constitution

A standing committee of the Board of Directors ("Board") of Niko Resources Ltd. (the "Corporation" or the "Company") consisting of members of the Board is hereby appointed by the Board from among their number and complying with all other legislation, regulations, TSX and NYSE listing standards agreements, articles and policies to which the Company and its business is subject is hereby established and designated as the "Audit Committee" (the "Committee").

2.0 Overall Purpose/Objectives

The Committee will assist the Board in fulfilling its oversight responsibilities, including:

2.1 the integrity of the Corporation's financial statements;

2.2 the integrity of the financial reporting process;

2.3 the system of internal control and management of financial risks;

2.4 the external auditors' qualifications and independence;

2.5 the external audit process and the Corporation's process for monitoring compliance with laws and regulations;

2.6 internal audit & reviews as required or scheduled;

2.7 disclosure of any material information;

2.8 information systems and office operation disaster recovery program; and

2.9 review and approve equity offering prospectus.

In performing its duties, the Committee will maintain effective working relationships with the Board, management and the external auditors. To perform his or her role effectively, each Committee member will obtain an understanding of the Corporation's business, operations, risks and related legislation, regulations and industry standards. So that the Audit Committee can discharge its duties as a whole, all Audit Committee members must be financially literate, and at least one member must have accounting or related financial management expertise.

3.0 Authority

The Board authorizes the Committee, within its scope of duties and responsibilities, to:

3.1 seek any information it requires from any employee of the Corporation (whose employees are directed to co-operate with any request made by the Committee);

3.2 seek any information it requires directly from external parties including the external auditors and independent engineer; and

3.3 obtain outside legal or other professional advice without seeking Board approval (however providing notice to the Chair of the Board).

4.0 Organization

The following provisions and regulations shall apply to the composition of the Committee:

4.1 the Committee shall consist of not less than three members of the Board of the Corporation;

4.2 the members of the Committee shall be independent members and unrelated to Management;

4.3 the Chair of the Committee shall be determined by the Board of the Corporation;

4.4 as a minimum, one member must be viewed as a financial expert;

4.5 two members of the Committee shall constitute a quorum thereof;

4.6 no business shall be transacted by the Committee except at a meeting of its members at which a quorum is present in person or by telephone or by a resolution in writing signed by all members of the Committee;

4.7 the meetings and proceedings of the Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board;

4.8 the Committee may invite such directors, officers or employees of the Corporation, the external auditors and independent engineer as it may see fit, to attend its meetings and take part in the discussion and consideration of the affairs of the Committee;

4.9 meetings shall be held not less than four times per year, generally coinciding with the release of interim or year-end financial information. Special meetings may be convened as required upon the request of the Committee Chair or any member. The external auditors and independent engineer may convene a meeting if they consider that it is desirable or necessary;

4.10 the proceedings of all meetings will be minuted;

4.11 the Committee shall meet separately, at least quarterly, with:

(a) management;

(b) external auditors.

5.0 Duties and Responsibilities

The Board hereby delegates and authorizes the Committee to carry out the following duties and responsibilities to the extent that these activities are not carried out by the Board as a whole:

5.1 Corporate Information and Internal Control

5.1.1 review and recommend for approval of the quarterly and annual financial statements, MD&A, press releases, annual report, AIF and Management Proxy Circular (salary and related benefit information will be reviewed and approved by the Compensation Committee) of the Company;

5.1.2 review of internal control systems maintained by the Corporation and the Company;

5.1.3 review of major changes to information systems;

5.1.4 review of spending authority and approval of limits;

5.1.5 review of significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a significant effect on the financial results of the Company;

5.1.6 review of significant proposed non-recurring events such as mergers, acquisitions or divestitures; and

5.1.7 review press releases or other publicly circulated documents containing financial information.

5.2 External Auditors

5.2.1 retain and terminate the external auditors (subject to unitholder approval);

5.2.2 review the terms of the external auditors' engagement and the appropriateness and reasonableness of the proposed engagement fees;

5.2.3 annually, obtain and review a report by the external auditors describing the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm or by any inquiry or investigation by governmental or professional authorities;

5.2.4 annually, a certificate attesting to the external auditors' independence, identifying all relationships between the external auditors and the Company;

5.2.5 annually, evaluate the external auditors' qualifications, performance and independence;

5.2.6 annually, to assure continuing auditor independence, consider the rotation of lead audit partner or the external auditor itself;

5.2.7 where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (National Policy #31 as adopted by the Canadian Securities Regulatory Authorities), and the planned steps for an orderly transition;

5.2.8 review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Policy #31, on a routine basis, whether or not there is a change of auditors;

5.2.9 pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence; and

5.2.10 set hiring policies for employees or former employees of the external auditors.

5.3 Audit

5.3.1 review the audit plan for the coming year with the external auditors and with management;

5.3.2 review with management and the external auditors any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting;

5.3.3 question management and the external auditors regarding significant financial reporting issues during the Fiscal period and the method of a resolution;

5.3.4 review any problems experienced by the external auditors in performing the audit, including any restrictions imposed by management or significant accounting issues in which there was a disagreement with management;

5.3.5 review audited annual financial statements and quarterly financial statements with management and the external auditors (including disclosures under "Management Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from management of all significant variances between comparative reporting periods;

5.3.6 review the auditors' report to management, containing recommendations of the external auditors', and management's response and subsequent remedy of any identified weaknesses; and

5.3.7 confirm with the external auditors, grants and payouts made, from time to time, under the Corporation's Long Term Incentive Plan, including those made to the senior officers.

5.4 Risk Management and Controls

5.4.1 review hedging strategies, policies, objectives and controls;

5.4.2 review, not less than quarterly, a mark to market assessment of the Corporation's hedge positions and counter party credit risk and exposure;

5.4.3 review adequacy of insurance coverage, outstanding or pending claims and premium costs;

5.4.4 review loss prevention policies and programs in the context of competitive and operational consideration; and

5.4.5 annually review authority limits for capital expenditures sales and purchases.

5.5 Annual Reserves Report and Reserves Assessment

5.5.1 review the Management's recommendations for the selection of an independent engineer(s) to evaluate the Corporation's reserves;

5.5.2 review the terms of the independent engineer's engagement for the annual reserve evaluation, including scope of work and the reasonableness of the proposed fees;

5.5.3 when there is a proposed change in an independent engineering firm, review all issues related to such change, including the planned steps for an orderly transition;

5.5.4 review the annual reserve evaluation (and any material interim updates) and request explanations for significant changes in scope, assumptions, methodologies and major revisions from prior year reports;

5.5.5 as appropriate, meet with the independent engineer to review any problems experienced by the independent engineer in preparing the annual reserve report (including any restrictions imposed by the Corporation or significant issues on which there was a disagreement with the Corporation) and to discuss any other matters the Committee wishes to raise;

5.5.6 review the Corporation's annual reserve report supplement, which analyses the Corporation's findings and development costs, reserve addition costs, net asset value and full life distribution forecast;

5.5.7 review all public disclosure documents containing reserve information prior to public release, including any prospectus, the annual report, the annual information form and management's discussion and analysis; and

5.5.8 periodically, receive and review reports from the Corporation on regulatory or industry standards concerning reserve assessments and reserve committees.

6.0 Other Duties and Responsibilities

6.1 The responsibilities, practices and duties of the Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Committee with the responsibility of reviewing items of a financial or control nature, of a risk management nature and of a reserves nature; and

6.2 The Committee shall periodically report to the Board the results of reviews undertaken and any associated recommendations.