NIKO RESOURCES LTD

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED MARCH 31, 2012

JUNE 27, 2012

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ABBREVIATIONS AND DEFINITIONS

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

"**2D**"	two dimensional	"**Mbbl**"	thousand barrels
"**3D**"	three dimensional	"**Mboe**"	thousand barrels of oil equivalent
"**bbl**"	barrel	"**Mcf**"	thousand cubic feet
"**bbls/d**"	barrels per day	"**Mcfe**"	thousand cubic feet of gas equivalent
"**Bcf**"	billion cubic feet	"**MMcfe**"	million cubic feet of gas equivalent
"**boe**"	barrels of oil equivalent	"**MMbbl**"	million barrels
"**boe/d**"	barrels of oil equivalent per day	"**MMbtu**"	million British thermal units
"**bopd**"	barrels of oil per day	"**MMcf**"	million cubic feet
"**CAD$**"	Canadian dollars	"**MMcf/d**"	million standard cubic feet per day
"**M$**"	thousands of U.S. dollars	"**NHV**"	net heating value
"**MM$**"	millions of U.S. dollars		

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

One MMBtu is equivalent to one Mcfe plus or minus up to 20%, depending on the composition and heating value of the natural gas in question.

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

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, together with any amendments thereto and all regulations promulgated thereunder;

"**BAPEX**" means the Bangladesh Petroleum Exploration Co., a wholly owned subsidiary of Petrobangla;

"**Black Gold Acquisition**" has the meaning ascribed thereto under "Business of the Company – Three Year History";

"**Block 2AB**" means the contract area known as Block 2AB located off the east coast of Trinidad and Tobago, as identified in a PSC entered into by Centrica Resources (Armada) Limited and Petroleum Company of Trinidad and Tobago Limited on July 8, 2009 with an interest therein being assigned to Voyager Energy (Trinidad) Ltd. with an effective date of July 8, 2009;

"**Block 4(b)**" means the contract area known as Block 4(b) located off the east coast of Trinidad and Tobago, as identified in a PSC entered into by Niko Resources (Block 4b Caribbean) Limited on April 18, 2011;

"**Block 5(c)**" means the contract area known as Block 5(c) located off the east coast of Trinidad and Tobago, as identified in a PSC entered into by Canadian Superior Energy Inc. on July 20, 2005, with an interest therein being assigned to the BG Group in 2007 and with an interest therein being assigned to Voyager Energy (Trinidad) Ltd. with an effective date of June 23, 2011;

"**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 GOB in April 2001; 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;

"**Block NCMA 2**" means the contract area known as Block NCMA 2 located off the north coast of Trinidad and Tobago, as identified in a PSC entered into by Niko Resources (NCMA2 Caribbean) Limited, RWE Dea Trinidad & Tobago Gmbh and Petroleum Company of Trinidad and Tobago Limited on April 18, 2011;

"**Block NCMA 3**" means the contract area known as Block NCMA 2 located off the north coast of Trinidad and Tobago, as identified in a PSC entered into by Niko Resources (NCMA3 Caribbean) Limited and Petroleum Company of Trinidad and Tobago Limited on April 18, 2011;

"**Bone Bay Block**" means the contract area known as Bone Bay located offshore south Sulawasi, Indonesia, as identified in a PSC entered into by Black Gold Ventures LLC, Marathon Indonesia (Bone Bay) Limited and BPMIGAS in November 2008 with an interest therein being assigned to Niko in November 2008;

"**BP**" means BP Exploration (Alpha) Limited;

"**BPMIGAS**" means Bedan Pelaksana Kegiatan Usaha Hulu Minyak Dan Gas Bumi, the executive agency for upstream oil and gas activity in Indonesia;

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

"**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;

"**Cendrawasih Block**" means the contract areas known as Cendrawasih located in the Cendrawasih Bay to the north of West Papua, Indonesia, as identified in a PSC entered into by Black Gold Cendrawasih LLC, Esso Exploration International Limited and BPMIGAS in May 2009 with an interest therein being assigned to Niko in May 2009;

"**Cendrawasih II Block**" means the contract areas known as Cendrawasih located in the Cendrawasih Bay to the north of West Papua, Indonesia, as identified in a PSC entered into by Niko Asia Ltd., Repsol Exploracion, S.A. and BPMIGAS effective May 18, 2010;

"**Cendrawasih III Block**" means the contract areas known as Cendrawasih located in the Cendrawasih Bay to the north of West Papua, Indonesia, as identified in a PSC entered into by Black Gold Ventures LLC, Repsol Exploracion, S.A. and BPMIGAS effective May 18, 2010;

"**Cendrawasih IV Block**" means the contract areas known as Cendrawasih located in the Cendrawasih Bay to the north of West Papua, Indonesia, as identified in a PSC entered into by Black Gold Ventures LLC, Repsol Exploracion, S.A. and BPMIGAS effective May 18, 2010;

"**Central Range Area**" means the contract areas known as Central Range Block – Shallow Horizon and Central Range Block – Deep Horizon spanning a strip from the west to east coasts onshore, Trinidad and Tobago, as identified in a PSC entered into by Voyager Energy (Trinidad) Ltd. and Petroleum Company of Trinidad and Tobago Limited on September 18, 2008;

"**CFPOA**" means the *Corruption of Foreign Public Officials Act*, S.C. 1998, c. 34, together with any amendments thereto and all regulations promulgated thereunder;

"**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 capital of the Company;

"**Convertible Debentures**" has the meaning ascribed thereto under "Business of the Company – Three Year History";

"**Criminal Code**" means the *Criminal Code of Canada*, R.S.C. 1985, c. C-46, together with any amendments thereto and all regulations promulgated thereunder;

"**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;

"**Debenture Indenture**" means the debenture indenture dated as of November 18, 2009, and amended and restated as of May 27, 2011, between the Company, Computershare Trust Company of Canada (as debenture trustee) and Maju Investments (Mauritius) Pte. Ltd. (as initial subscriber and Debentureholder), pursuant to which the Convertible Debentures are created and issued;

"**Debentureholders**" means the holders from time to time of Convertible Debentures;

"**East Bula Block**" means the contract areas known as East Bula located in Seram northeast, Indonesia, as identified in a PSC entered into by Black Gold East Bula LLC, Niko Resources (Overseas XVII) Limited and BPMIGAS effective November 30, 2009;

"**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 Company ended March 31, 2007; "**Fiscal 2008**" means the fiscal year of the Company ended March 31, 2008; "**Fiscal 2009**" means the fiscal year of the Company ended March 31, 2009; "**Fiscal 2010**" means the fiscal year of the Company ended March 31, 2010; "**Fiscal 2011**" means the fiscal year of the Company ended March 31, 2011; "**Fiscal 2012**" means the fiscal year of the Company ended March 31, 2012; "**Fiscal 2013**" means the fiscal year of the Company ending March 31, 2013; and "**Fiscal 2014**" means the fiscal year of the Company ending March 31, 2014;

"**FPSO**" means floating production storage and offloading vessel;

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

"**GGCL**" means Gujarat Gas Company Limited, the Indian subsidiary of British Gas PLC;

"**GHPL**" means Government Holdings (Private) Ltd., which manages the Government of Pakistan's working interest in upstream oil and gas ventures;

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

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

"**GPSA**" and "**GSPA**" mean gas purchase and sale agreement;

"**GRI**" means the Government of the Republic of Indonesia;

"**GSEG**" means the Gujarat State Electrical Generation Ltd.;

"**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;

"**GTT**" means the Government of Trinidad and Tobago;

"**Guayaguayare Area**" means the contract areas known as Guayaguayare Block – Shallow Horizon and Guayaguayare Block – Deep Horizon located on and off the southeast coast of Trinidad and Tobago, as identified in two PSCs entered into by Voyager Energy (Trinidad) Ltd. and Petroleum Company of Trinidad and Tobago Limited on July 7, 2009;

"**Halmahera II Block**" means the contract areas known as Halmahera II located in West Papua, Indonesia, as identified in a PSC entered into by Statoil Indonesia Halmahera II AS, Niko Resources (Halmahera II) Limited and BPMIGAS effective December 19, 2011;

"**Halmahera-Kofiau Block**" means the contract areas known as Halmahera-Kofiau located in West Papua, Indonesia, as identified in a PSC entered into by Black Gold Halmahera-Kofiau LLC, Niko Resources (Overseas XVI) Limited and BPMIGAS effective November 30, 2009;

"**Hazira Field**" means the contract area known as the Hazira Field located onshore and offshore in Gujarat State, India, as identified in a PSC entered into by Niko, GSPC and the GOI in September 1994;

"**Indonesian Blocks**" means, collectively, Bone Bay Block, Cendrawasih Block, Cendrawasih II Block, Cendrawasih III Block, Cendrawasih IV Block, East Bula Block, Halmahera-Kofiau Block, Kofiau Block, Kumawa Block, North Makassar Block, Seram Block, South East Ganal I Block, South Matindok Block, Sunda Strait I Block, West Papua IV Block, West Sageri Block, Obi Block, North Ganal Block, Halmahera II Block, South East Seram Block and Lhokseumawe Block;

"**JVA**" means the Joint Venture Agreement between NRBL 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;

"**Kofiau Block**" means the contract area known as Kofiau located offshore from the Bird's Head of West Papua, Indonesia as identified in a PSC entered into by Niko Resources (Overseas IX) LLC, Black Gold Kofiau LLC and BPMIGAS in May 2009;

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

"**Kumawa Block**" means the contract area known as Kumawa located offshore to the south of West Papua, Indonesia as identified in a PSC entered into by Niko Resources (Overseas VII) Limited, Black Gold Kumawa LLC and BPMIGAS in May 2009 with an interest therein being assigned to Niko in May 2009;

"**LBDP**" means land based drilling platform;

"**Lhokseumawe Block**" means the contract area known as Lhokseumawe located offshore in western Indonesia, as identified in a PSC entered into by Zaratex N.V. and BPMIGAS effective October 2005;

"**LPG**" means liquefied petroleum gas;

"**Madagascar Block**" means the contract area located off the west coast of Madagascar, as identified in a PSC entered into by EnerMad Corp. and OMNIS in October 2007;

"**MG Block**" means the contract area known as the Mayaro-Guayaguayare Bay Block located off the east coast of Trinidad and Tobago, as identified in an exploration and production license between Petroleum Company of Trinidad and Tobago Limited and Canadian Superior Trinidad and Tobago Ltd. dated July 27, 2007;

"**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;

"**NGL**" means natural gas liquids, being those hydrocarbon components that can be recovered from natural gas as liquids, including but not limited to ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

"**Niko**" or the "**Company**" means Niko Resources Ltd. and, where the context requires, includes its wholly-owned subsidiaries;

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

"**NI 52-110**" means Canadian Securities Administrators' National Instrument 52-110 *Audit Committees*;

"**North Ganal Block**" means the contract area known as North Ganal located in the Makassar Strait, in the province of East Kalimantan, Indonesia, as identified in a PSC entered into by Niko Resources (North Ganal) Limited, Statoil Indonesia North Ganal AS, North Ganal Energy Ltd., ENI North Ganal Limited, GDF Suez New Projects Indonesia B.V. and BPMIGAS effective November 21, 2011;

"**North Makassar Block**" means the contract areas known as North Makassar located in the Makassar Strait, Indonesia, as identified in a PSC entered into by Baruna Nusantara Energy Ltd., Niko Resources (Overseas XIV) Limited and BPMIGAS effective November 30, 2009;

"**NRBL**" means Niko Resources (Bangladesh) Ltd., a wholly-owned subsidiary of Niko;

"**Obi Block**" means the contract areas known as Obi located in West Papua, towards eastern Indonesia and south of Halmahera Island, as identified in a PSC entered into by Statoil Indonesia Obi AS, Niko Resources (Obi) Limited, Zimorex NV and BPMIGAS effective November 21, 2011;

"**OMNIS**" means the Office of National Mines and Strategic Industries in Madagascar;

"**Pakistan Blocks**" means, collectively, 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 Resources (Pakistan) Ltd., the President of the Islamic Republic of Pakistan and GHPL in March 2008;

"**Petrobangla**" means the Bangladesh Oil, Gas and Mineral Corporation, the Bangladesh state-owned oil and gas company;

"**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., Vast Exploration (Kurdistan) Inc., Groundstar Resources Kurdistan Ltd. and the KRG effective May 14, 2008;

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

"**Reliance JOAs**" means, collectively, the Joint Operating Agreements between the Company, Reliance Industries Limited and BP Exploration (Alpha) Limited signed on February 21, 2011 (covering the operation of D6 Block, D4 Block and NEC-25);

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

"**Ryder Scott Report**" means the independent reserves and economic evaluation of Niko's oil and natural gas interests in the D6 Block and Block 9 prepared by Ryder Scott dated June 20, 2012 and effective March 31, 2012;

"**Seram Block**" means the contract area known as Seram located offshore to the northeast of the island of Seram, Indonesia, as identified in a PSC entered into by Niko Resources (Overseas VI) Limited, Black Gold Indonesia LLC and BPMIGAS effective November 13, 2008;

"**South East Ganal I Block**" means the contract area known as South East Ganal I located in the Makassar Strait, Indonesia as identified in a PSC entered into by Niko Resources (Overseas III) Limited, Kaizan South East Ganal I LLC and BPMIGAS effective November 13, 2008;

"**South East Seram Block**" means the contract area known as South East Seram located offshore to the southeast of the island of Seram, Indonesia, as identified in a PSC entered into by Niko Resources (South East Seram) Ltd. and BPMIGAS effective December 19, 2011;

"**South Matindok Block**" means the contract area known as South Matindok located offshore east Sulawasi, Indonesia, as identified in a PSC entered into by Niko Resources (Overseas IV) Limited, Kaizan South Matindok LLC and BPMIGAS effective November 13, 2008;

"**Statoil**" means Statoil ASA;

"**subsidiary**" has the meaning ascribed thereto in the ABCA;

"**Sunda Strait I Block**" means the contract areas known as Sunda Strait I located in the Sunda Strait, Indonesia, as identified in a PSC entered into by Komodo Energy LLC, Niko Resources (Overseas XI) Limited and BPMIGAS effective May 18, 2010;

"**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;

"**Trinidad Blocks**" means, collectively, Block 2AB, the Central Range Area, the Guayaguayare Area, Block NCMA 2, Block NCMA 3, Block 4(b), Block 5(c) and the MG Block;

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

"**Voyager Acquisition**" has the meaning ascribed thereto under "Business of the Company – Three Year History";

"**West Papua IV Block**" means the contract area known as West Papua IV located in southwest Papua as identified in a PSC entered into by BPMIGAS, Black Gold West Papua IV LLC and Niko Resources (Overseas XV) Limited effective November 30, 2009; and

"**West Sageri Block**" means the contract area known as West Sageri located in the Makassar Strait, Indonesia as identified in a PSC entered into by Niko Resources (Overseas II) Limited, Kaizan West Sageri LLC and BPMIGAS effective November 13, 2008.

In this Annual Information Form, references to "**dollars**", "**$**" and "**US$**" are to the currency of the United States of America, 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. More particularly and without limitation, this Annual Information Form contains forward-looking statements relating to the following:

- the performance characteristics of the Company's oil, NGL and natural gas properties;
- oil, NGL and natural gas production levels;
- the size of the oil, NGL and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;

- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs

The forward-looking statements contained in this Annual Information Form are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

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

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

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.

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 Exploration (Block 9) Limited is an indirect wholly-owned subsidiary of Niko with total revenues exceeding 10% of the consolidated revenues of Niko. Niko Exploration (Block 9) Limited also has total assets of approximately 3% of the consolidated assets of Niko. Niko Exploration (Block 9) Limited was incorporated and currently exists under the laws of Bermuda.

Niko (NECO) Limited is an indirect wholly-owned subsidiary of Niko with total revenues and total assets exceeding 10% of the consolidated revenue and consolidated assets, respectively, of Niko. Niko (NECO) Limited was incorporated and currently exists under the laws of the Cayman Islands.

Nikoresources (Cyprus) Limited is a wholly-owned subsidiary of Niko with total assets exceeding 10% of the consolidated assets of Niko. Nikoresources (Cyprus) Limited was incorporated and currently exists under the laws of Cyprus.

Niko (NELPIO) Limited is an indirect wholly-owned subsidiary of Niko with total assets of approximately 3% of the consolidated assets of Niko. Niko (NELPIO) Limited was incorporated and currently exists under the laws of the Cayman Islands.

Nikoresources (Kurdistan) Limited is an indirect wholly-owned subsidiary of Niko with total assets of approximately 5% of the consolidated assets of Niko. Nikoresources (Kurdistan) Limited was incorporated and currently exists under the laws of Cyprus.

Voyager Energy (Barbados) Ltd. is an indirect wholly-owned subsidiary of Niko with total assets of approximately 4% of the consolidated assets of Niko. Voyager Energy (Barbados) Ltd. was incorporated and currently exists under the laws of Barbados.

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: (i) India, where it currently holds interests in two onshore blocks, three offshore blocks and one off/onshore block; (ii) Bangladesh, where it currently holds interests in three onshore blocks; (iii) Pakistan, where it currently holds interests in four offshore blocks; (iv) the Kurdistan Region of Iraq, where it currently holds an interest in one onshore block; (v) Indonesia, where it currently holds interests in 21 offshore blocks; (vi) Madagascar, where it currently holds an interest in one offshore block; and (vii) Trinidad and Tobago, where it currently holds interests in six offshore blocks, two onshore areas and two off/onshore areas. 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".

Three Year History

The following is a description of events and conditions that have influenced the general development of the business during Fiscal 2010, Fiscal 2011 and Fiscal 2012.

In April 2009, gas production from the Dhirubhai 1 and 3 gas fields in the D6 Block commenced.

From April 2009 to March 2010, the Company and its partner signed 39 GSPAs with customers in various industries for the supply of natural gas from the D6 Block.

In May 2009, the Company acquired rights in three additional offshore exploration blocks in Indonesia: the Kofiau Block, the Kumawa Block and the Cendrawasih Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSCs in respect of these blocks.

In November 2009, the Company acquired rights in four additional offshore exploration blocks in Indonesia: the East Bula Block, the Halmahera-Kofiau Block, the North Makassar Block and the West Papua IV Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSCs in respect of these blocks.

In December 2009, the Company acquired all of the outstanding shares of Black Gold Energy LLC (the "**Black Gold Acquisition**") through a wholly-owned subsidiary of the Company, Nikoresources (Cyprus) Limited, for a purchase price of $300 million. The Black Gold Acquisition increased the Company's working interest in the Indonesian Blocks.

Also in December 2009, in order to help finance the Black Gold Acquisition, the Company entered into a CAD$310 million convertible debenture credit facility. The convertible debentures under such facility (the "**Convertible Debentures**") bear a coupon rate of 5%, have a conversion price of CAD$110.50 per Common Share and mature on

December 30, 2012. The Debenture Indenture was amended and restated as of May 27, 2011 to include a provision that permits the Company, at its option, to repay the Convertible Debentures, plus accrued interest thereon, at maturity by issuing to the Debentureholders freely tradeable Common Shares. See "Description of Capital Structure – Convertible Debentures".

In March 2010, the Company acquired all of the outstanding shares of Voyager Energy Ltd. (the "**Voyager Acquisition**"), a private company with interests in five PSCs in Trinidad and Tobago. The Voyager Acquisition was completed by way of a plan of arrangement under the ABCA. Upon completion of the Voyager Acquisition, the Company issued an aggregate of 397,379 Common Shares to the former Voyager shareholders.

In May 2010, the Company signed four PSCs with the GRI for the Sunda Strait I Block, the Cendrawasih II Block, the Cendrawasih III Block and the Cendrawasih IV Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSCs for these blocks.

In January 2011, the Company farmed out a portion of its interest in each of the East Bula Block and the Seram Block. As a result of the farm-out agreement, the Company holds a 55% working interest in each Block.

In April 2011, the Company signed three PSCs with the GTT for Block NCMA 2, Block NCMA 3 and Block 4(b). See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Trinidad and Tobago" for a description of the terms of the PSCs for these blocks.

On May 24, 2011, the Company announced that it had reached an agreement with Statoil pursuant to which Statoil, through its subsidiaries, will become a joint venture participant and earn 40% of the Company's working interest in each of the North Makassar Block, the West Papua IV Block and the Halmahera-Kofiau Block.

In June 2011, the Company announced that, in connection with a formal investigation into allegations of improper payments in Bangladesh by the Company, it pleaded guilty to one count of bribery under the CFPOA in respect of two specific incidents that occurred in 2005. See "Legal Proceedings and Regulatory Actions – Canadian Authorities Investigation".

In September 2011, the Company farmed out a portion of its interest in the Kofiau Block. As a result of the farm-out agreement, the Company holds a 57.50% working interest in the Kofiau Block.

In November 2011, the Company signed a multi-year deepwater rig contract for its Indonesia operations for a four-year term with the option of one additional year with a subsidiary of Diamond Offshore, a major deepwater drilling contractor, for its Ocean Monarch semi submersible rig.

Also in November 2011, the Company spudded its first offshore well in Block 2AB through the Rowan Gorilla III rig at the Stalin prospect.

Also in November 2011, the Company signed two PSCs with the GRI for the North Ganal Block and the Obi Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSCs for these blocks.

In December 2011, the Company was formally assigned an interest in the MG Block by GTT. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Trinidad and Tobago" for a description of the terms of the license for the MG Block.

Also in December 2011, the Company signed two PSCs with the GRI for the South East Seram Block and the Halmahera II Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSCs for these blocks.

In February 2012, the Company farmed out a portion of its interest in the Obi Block. As a result of the farm-out agreement, the Company holds a 42% working interest in the Obi Block. The transfer of such interest is pending the approval of the GRI.

In January 2012, the Company entered into an agreement for credit facilities totaling US$250 million. The first is a US$225 million senior secured syndicated credit facility and the second is a US$25 million senior secured operating facility. The syndicated facility was jointly arranged by Scotia Capital and RBC Capital Markets and includes participation by a total of seven international banks. Each facility is available for general corporate purposes and has a revolving period of three years that is extendible annually. Borrowings under the facilities carry an interest rate of US$ Libor plus an applicable margin that steps up based on a leverage ratio.

Recent Developments

In April 2012, the Company farmed in to a PSC for the Lhokseumawe Block. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia" for a description of the terms of the PSC for the Lhokseumawe Block.

Also in April 2012, the Company's operating partner in the Lhokseumawe Block, Zaratex N.V., initiated drilling operations on the Candralila-1 well in western Indonesia. The Candralila-1 well is the first of two wells to be drilled back-to-back on the block using the Hercules 208 jack-up rig.

In June 2012, the Candralila-1 well was plugged and abandoned without reaching target depth due to mechanical problems. The well had oil and gas shows while drilling and partial logs recovered had indications of potential prospectivity.

In May 2012, the Company chose to relinquish its interest in the D4 Block in India.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Niko will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Niko. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Personnel

As at March 31, 2012, Niko had 31 employees at its head office in Calgary, 82 employees at its India offices, 19 employees at its Bangladesh office, one employee at its Pakistan office, 21 employees at its Kurdistan office, three employees at its Madagascar office, 26 employees at its Trinidad and Tobago offices and 94 employees at its Indonesia offices.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "**Statement**") is dated June 20, 2012 and is effective March 31, 2012. The preparation date of the information regarding reserves in the Statement was June 20, 2012.

The future net revenue numbers presented throughout the 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 estimated reserves of crude oil, natural gas and NGL and the estimated 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. The Ryder Scott Report evaluates the Company's interests in the D6 Block in India and Block 9 in Bangladesh. For Fiscal 2011, Ryder Scott evaluated the Company's interests in the D6 Block, the Hazira Field and the Surat Block in India and Block 9 in Bangladesh.

There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserves 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 reserves and production are located in India (D6 Block) and Bangladesh (Block 9). The Company has other properties in India (the Hazira Field and the Surat Block) as well as properties in Canada with reserves. The Company believes that the reserves attributable to its interests in the Hazira Field and the Surat Block in India and its Canadian properties collectively constitute less than 1% of the Company's total reserves and therefore have not been evaluated and are not included in the reserves information provided below.

The Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 is attached hereto as Appendix "A" and the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3 is attached hereto as Appendix "B".

Reserves Disclosure – Total India and Bangladesh

The following tables detail the estimated aggregate gross and net reserves of the Company for both the D6 Block in India and Block 9 in Bangladesh, estimated using forecast prices and costs, as well as the estimated 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 Prices and Costs As at March 31, 2012					
	Light and Medium Crude Oil		Natural Gas		NGL	
Reserves Category	Gross (Mbbl)	Net[1] (Mbbl)	Gross (MMcf)	Net[1] (MMcf)	Gross (Mbbl)	Net[1] (Mbbl)
PROVED						
Developed Producing	68	67	170,611	147,841	626	554
Developed Non-Producing	-	-	35,290	27,353	365	332
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	68	67	205,901	175,194	991	886
PROBABLE	23	23	161,688	97,625	539	332
TOTAL PROVED PLUS PROBABLE	91	90	367,589	272,819	1,530	1,218

Note:

(1) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI and the GOB.

Reserves Category	Net Present Values of Future Net Revenues – India and Bangladesh[1] Forecast Prices and Costs As at March 31, 2012					
	Before Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year[2]
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	($/boe)
PROVED						
Developed Producing	573	505	448	399	358	17.73
Developed Non-Producing	73	60	49	41	34	10.14
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	646	565	497	440	392	16.49
PROBABLE	444	327	245	186	143	14.72
TOTAL PROVED PLUS PROBABLE	1,090	892	742	626	535	15.86

Note:

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

(2) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI and the GOB.

Reserves Category	Net Present Values of Future Net Revenues – India and Bangladesh[1] Forecast Prices and Costs As at March 31, 2012				
	After Income Taxes Discounted at (%/year)				
	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED					
Developed Producing	532	470	418	374	337
Developed Non-Producing	73	60	50	41	33
Undeveloped	-	-	-	-	-
TOTAL PROVED	605	530	468	415	370
PROBABLE	379	278	206	155	118
TOTAL PROVED PLUS PROBABLE	984	808	674	570	488

Note:

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

The following table provides the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for both the D6 Block in India and Block 9 in Bangladesh, estimated using forecast prices and costs and calculated without discount:

(MM$)	Future Net Revenue India and Bangladesh Properties As at March 31, 2012 Forecast Prices and Costs (Undiscounted) Proved Reserves	 Proved Plus Probable Reserves
Revenue[1]	1,235	2,088
Profit Petroleum[2]	(111)	(329)
Royalties	(77)	(131)
Operating Costs	(292)	(408)
Development Costs	(66)	(82)
Abandonment and reclamation costs	(43)	(48)
Future Net Revenue Before Income Taxes	646	1,090
Income Taxes	(41)	(106)
Future Net Revenue After Income Taxes	605	984

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production from the D6 Block in India, the purchasers of natural gas pay a marketing margin over and above the contracted price. Revenue as presented above is the contracted price plus the marketing fee plus the amount of royalties levied by the GOI.

(2) Under the terms of the PSC for the D6 Block, the GOI is entitled to a percentage share of the profit gas produced from the D6 Block, 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 the Indian PSCs – Offshore Blocks". Under the terms of the PSC for Block 9, the GOB 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 – Bangladesh".

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 the D6 Block in India and Block 9 in Bangladesh, estimated using forecast prices and costs and calculated using a discount rate of 10%:

Reserves Category	Future Net Revenue – India and Bangladesh By Production Group As at March 31, 2012 Production Group	 Future Net Revenue Before Income Taxes (Discounted at 10%/year) (MM$)	 Unit Value[3]
Proved Reserves	Light and Medium Oil[1] Natural Gas[2]	- 497	- US$2.75/Mcfe
Proved Plus Probable Reserves	Light and Medium Oil[1] Natural Gas[2]	- 742	- US$2.64/Mcfe

Notes:

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

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

(3) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI and the GOB.

Reserves Disclosure – India

The following tables detail the aggregate gross and net reserves of the Company for the D6 Block, estimated 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 – D6 Block, India[(1)] Forecast Prices and Costs As at March 31, 2012					
	Light and Medium Crude Oil		Natural Gas		NGL	
Reserves Category	Gross (Mbbl)	Net[(2)] (Mbbl)	Gross (MMcf)	Net[(2)] (MMcf)	Gross (Mbbl)	Net[(2)] (Mbbl)
PROVED						
Developed Producing	68	67	117,669	113,810	455	444
Developed Non-Producing	-	-	14,273	13,741	300	290
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	68	67	131,942	127,551	755	734
PROBABLE	23	23	55,010	48,607	199	176
TOTAL PROVED PLUS PROBABLE	91	90	186,952	176,158	954	910

Notes:

(1) The above table presents the reserves numbers contained in the Ryder Scott Report for the D6 Block.

(2) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI and the GOB.

	Net Present Values of Future Net Revenues – D6 Block, India[(1)] Forecast Prices and Costs As at March 31, 2012					
	Before Income Taxes Discounted at (%/year)					Unit Value[(2)] Before Income Tax Discounted at 10%/year
Reserves Category	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	(US$/boe)
PROVED						
Developed Producing	539	472	416	369	329	21.35
Developed Non-Producing	58	48	39	32	26	15.30
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	597	520	455	401	355	20.64
PROBABLE	367	266	196	145	110	23.56
TOTAL PROVED PLUS PROBABLE	964	786	651	546	465	21.44

Notes:

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

(2) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI.

	Net Present Values of Future Net Revenues – D6 Block, India[1] Forecast Prices and Costs As at March 31, 2012				
	After Income Taxes Discounted at (%/year)				
Reserves Category	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED					
Developed Producing	498	437	386	344	307
Developed Non-Producing	58	48	39	32	27
Undeveloped	-	-	-	-	-
TOTAL PROVED	556	485	425	376	334
PROBABLE	303	217	157	115	85
TOTAL PROVED PLUS PROBABLE	859	702	582	491	419

Notes:

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

The following table provides the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for the D6 Block, estimated using forecast prices and costs and calculated without discount:

	Future Net Revenue D6 Block, India As at March 31, 2012	
	Forecast Prices and Costs (Undiscounted)	
(MM$)	Proved Reserves	Proved Plus Probable Reserves
Revenue[1]	1,039	1,610
Profit Petroleum[2]	(41)	(107)
Royalties	(77)	(131)
Operating Costs	(242)	(321)
Development Costs	(44)	(45)
Abandonment and reclamation costs	(38)	(42)
Future Net Revenue Before Income Taxes	597	964
Income Taxes	(41)	(106)
Future Net Revenue After Income Taxes	556	858

Notes:

(1) Under the terms of the gas sales contracts that are currently in place with respect to the Company's natural gas production from the D6 Block, the purchasers of natural gas pay a marketing margin over and above the contracted price. Revenue as presented above is the contracted price including the marketing fee plus the amount of royalties levied by the GOI.

(2) Under the terms of the applicable PSCs, the GOI is entitled to a percentage share of the profit gas produced from the Company's 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 the Indian PSCs – Offshore Blocks".

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 the D6 Block, estimated using forecast prices and costs and calculated using a discount rate of 10%:

	Future Net Revenue – D6 Block, India By Production Group As at March 31, 2012		
Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year) (MM$)	Unit Value(3)
Proved Reserves	Light and Medium Oil(1) Natural Gas(2)	- 455	- US$3.44/Mcfe
Proved Plus Probable Reserves	Light and Medium Oil(1) Natural Gas(2)	- 651	- US$3.57/Mcfe

Notes:

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

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

(3) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI.

Reserves Disclosure – Bangladesh

The following tables detail the gross and net reserves of the Company for Block 9, estimated using forecast prices and costs, as well as the 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 – Block 9, Bangladesh Forecast Price and Costs As at March 31, 2012					
	Light and Medium Crude Oil		Natural Gas		NGL	
Reserves Category	Gross (Mbbl)	Net(1) (Mbbl)	Gross (MMcf)	Net(1) (MMcf)	Gross (Mbbl)	Net(1) (Mbbl)
PROVED						
Developed Producing	-	-	52,942	34,031	171	110
Developed Non-Producing	-	-	21,018	13,612	65	42
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	-	-	73,960	47,643	236	152
PROBABLE	-	-	106,677	49,019	340	156
TOTAL PROVED PLUS PROBABLE	-	-	180,637	96,662	576	308

Note:

(1) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOB.

	Net Present Values of Future Net Revenues – Block 9, Bangladesh[1] Forecast Prices and Costs As at March 31, 2012					
	Before and After Income Taxes Discounted at (%/year)[2]					Unit Value[3] Before Income Tax Discounted at 10%/year
Reserves Category	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	(US$/boe)
PROVED						
Developed Producing	34	33	32	31	30	5.52
Developed Non-Producing	15	12	10	8	7	4.38
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	49	45	42	39	37	5.19
PROBABLE	76	61	49	40	33	5.89
TOTAL PROVED PLUS PROBABLE	125	106	91	79	70	5.55

Notes:

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

(2) Income taxes are not applicable to Block 9, as specified in the PSC for Block 9.

(3) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOB.

The following table provides the elements of future net revenue attributable to proved reserves and proved plus probable reserves of the Company for Block 9, estimated using forecast prices and costs and calculated without discount:

	Future Net Revenue Block 9, Bangladesh As at March 31, 2012	
	Forecast Prices and Costs (Undiscounted)	
(MM$)	Proved Reserves	Proved Plus Probable Reserves
Revenue	197	479
Profit Petroleum[1]	(70)	(222)
Operating Costs	(51)	(87)
Development Costs	(22)	(37)
Abandonment and reclamation costs	(5)	(7)
Future Net Revenue Before Income Taxes	49	126
Income Taxes[2]	-	-
Future Net Revenue After Income Taxes	49	126

Notes:

(1) Under the terms of the PSC for Block 9, the GOB 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".

(2) Income taxes are not applicable to Block 9 as specified in the PSC.

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 Block 9, estimated using forecast prices and costs and calculated using a discount rate of 10%:

	Future Net Revenue – Block 9, Bangladesh By Production Group As at March 31, 2012		
Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/year) (MM$)	Unit Value(2)
Proved Reserves	Natural Gas(1)	42	$0.87/Mcfe
Proved Plus Probable Reserves	Natural Gas(1)	91	$0.92/Mcfe

Notes:

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

(2) Unit value is based on net reserves. "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOB.

Pricing Assumptions

The following tables detail the reference prices and inflation rate assumptions as of March 31, 2012 utilized by Ryder Scott in the Ryder Scott Report for estimating reserves data 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, 2012 Forecast Prices and Costs(1) for D6 Block									
	D6 – Oil	D6 – Oil	D6 – NGL	D6 – NGL	D6 – D1 & D3 Natural Gas	D6 – MA Gas		Brent Blended Price(2)	
Fiscal Year	Proved ($US/bbl)(2)	Proved Plus Probable ($US/bbl)(2)	Proved ($US/bbl)(2)	Proved Plus Probable ($US/bbl)(2)	Proved ($US/Mcf)	Proved ($US/Mcf)	Inflation Rate (%/Year)(3)	Calendar Year	(US$/bbl)
Forecast									
2013	111.20	111.05	110.98	110.92	3.82	4.25	3	2012	121.00
2014	-	106.60	105.01	104.96	3.82	4.25	3	2013	115.00
2015	-	-	97.76	97.71	9.99	11.12	2	2014	107.00
2016	-	-	91.48	91.45	9.29	10.34	2	2015	99.30
2017	-	-	89.08	89.09	9.04	10.06	2	2016	95.37
Average thereafter	-	-	92.61	94.54	9.35	10.53	2	Average thereafter	103.56

Notes:

(1) The natural gas prices shown in the table were based on contractual agreements and sales data. The natural gas prices for Fiscal 2015 and onwards reflect the anticipated contractual prices upon redetermination as estimated by the Company. The oil and NGL prices shown in 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 for the D6 Block exclude the marketing margin of US$0.135/MMBtu.

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

(3) The forecast inflation rate provided by Ryder Scott is as shown above and the inflation rates are applied to the operating and investment costs only.

Summary of Pricing and Inflation Rate Assumptions
As of March 31, 2012
Forecast Prices and Costs(1)
for Block 9

	Block 9 – NGL	Block 9 – NGL	Block 9 – Natural Gas		Brent Blended Price(2)	
Fiscal Year	Proved ($US/bbl)	Proved Plus Probable ($US/bbl)	($US/Mcf)(2)	Inflation Rate (%/Year)(3)	Calendar Year	(US$/bbl)
Forecast						
2013	119.70	119.43	2.31	3	2012	121.00
2014	113.21	113.00	2.31	3	2013	115.00
2015	105.33	105.27	2.31	2	2014	107.00
2016	98.25	98.25	2.31	2	2015	99.30
2017	95.82	95.83	2.31	2	2016	95.37
Average thereafter	99.86	103.96	2.31	2	Average thereafter	103.56

Notes:

(1) The NGL and natural gas prices shown in 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 reference price used by Ryder Scott is Brent Blended.

(3) The forecast inflation rate provided by Ryder Scott is as shown above and the inflation rates are applied to the operating and investment costs only.

The Company's weighted average prices received in India (D6 Block only) prior to a reduction for any profit petroleum amounts payable to the GOI in Fiscal 2012 were $109.49/bbl for oil and $4.03/Mcf for natural gas. Weighted average NGL and natural gas prices received by the Company in Bangladesh prior to a reduction for any profit petroleum amounts payable to the GOB in Fiscal 2012 were $117.05/bbl for NGL and $2.31/Mcf for natural gas.

Reconciliations of Changes in Reserves

The following table reconciles the changes in the gross reserves estimates for the Company's India properties as at March 31, 2011 and as at March 31, 2012 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type – 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, 2011 (Hazira Field, Surat Block and D6 Block)	131	78	209	675,595	314,699	990,294
March 31, 2011 (Hazira Field and Surat Block)	(40)	(47)	(87)	(4,232)	(1,584)	(5,816)
March 31, 2011 (Block D6)	91	31	122	671,363	313,115	984,478
Extensions & Improved Recovery	-	-	-	-	-	-
Technical Revisions	149	(8)	141	(484,725)	(258,105)	(742,830)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(172)	-	(172)	(54,696)	-	(54,696)
March 31, 2012 (D6 Block)	68	23	91	131,942	55,010	186,952

The following table reconciles the changes in the gross reserves estimates for the Company's Bangladesh properties as at March 31, 2011 and as at March 31, 2012 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type – Bangladesh
Forecast Prices and Costs

	Associated and Non-Associated Gas		
Factors	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)
March 31, 2011	96,371	106,804	203,175
Extensions & Improved Recovery	-	-	-
Technical Revisions	-	-	-
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	(890)	(127)	(1,017)
Production	(21,521)	-	(21,521)
March 31, 2012	73,960	106,677	180,637

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 three most recent financial years and, in the aggregate, before that time:

Undeveloped Reserves First Attributed Forecast Prices and Costs			
	Light and Medium Oil	Natural Gas	NGL
	Gross (Mbbl)	Gross (MMcf)	Gross (Mbbl)
PROVED UNDEVELOPED			
2012	-	-	-
2011	-	-	-
2010	-	-	-
Prior thereto	-	-	-
PROBABLE UNDEVELOPED			
2012	-	-	-
2011	-	-	-
2010	-	-	-
Prior thereto	-	86,630	279

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 probable undeveloped natural gas and NGL reserves for Block 9 in Bangladesh.

The probable undeveloped reserves in Block 9 are expected to be developed over the next two years and development includes additional drilling.

The Company's undeveloped properties, including NEC-25 in India, Chattak and the developed Feni property in Bangladesh, the Pakistan Blocks, the Qara Dagh Block in Kurdistan, the Madagascar Block, the Indonesian Blocks and the Trinidad Blocks, 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 the Statement, see the Company's management's discussion and analysis of financial condition, results of operations and cash flows for Fiscal 2012 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 the D6 Block in India and Block 9 in Bangladesh attributable to proved reserves and proved plus probable reserves (both estimated using undiscounted and forecast prices and costs):

Future Development Costs – D6 Block, India[1]		
(MM$)	Proved Reserves	Proved Plus Probable Reserves
Year		
2013	34	34
2014	10	10
2015	-	-
2016	-	-
2017	-	-
Remainder	38	42
Total Undiscounted	82	86

Note:

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

Future Development Costs – Block 9, Bangladesh[1]		
(MM$)	Proved Reserves	Proved Plus Probable Reserves
Year		
2013	1	1
2014	16	31
2015	-	-
2016	5	5
2017	1	1
Remainder	4	6
Total Undiscounted	27	44

Note:

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

The source of funding for future development costs of the Company's reserves is expected to be derived from a combination of current cash balances and cash flow from operations. The interest and other costs of any external funding are not included in the reserves and future net revenue estimates. Management of the Company does not anticipate that interest or other funding costs would make 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 is at March 31, 2012 unless otherwise indicated. The Company has completed all work obligations except as noted in the discussion below and all relinquishments required under the agreements except as noted in the acreage tables below.

Terms of the Various Agreements

For all properties, the various agreements (PSC, PSA or JVA) grant the Company the right to conduct petroleum operations that include oil and gas exploration, development and production activities. The various governments are the sole owners of any oil and gas reserves for the lands under agreement. The various agreements enable the Company and its partners to recover exploration, development and production costs and expenses (as defined in the various agreements) incurred for the block from the oil and gas produced from the block.

For all properties, the Company is required to provide a guarantee, standby letter of credit or a parent company guarantee as a performance security guarantee related to the work commitment in the exploration periods.

Except as specifically noted below for individual properties, all agreements provide for the right to market natural gas to third parties at a market determined price and for the right to market crude oil produced at international prices.

For all properties, should the Company fail to fulfill its obligations or in the event of a major breach of contract, the relevant government has the right to terminate the agreement in question. Unless specifically provided for in the agreements, each agreement terminates at the end of the exploration period if no commercial discovery is made.

For all properties, on the expiry or termination of a PSC, PSA or JVA or relinquishment of part of a contract area under a PSC, PSA or JVA, the operator will remove all equipment and installations in a manner agreed with the government pursuant to an abandonment plan and the operator will perform all necessary site restoration activities in accordance with good international petroleum industry practice. In many countries, the Company must fund these costs over time with an annual contribution to a site restoration fund in accordance with the scheme framed by the government or specified in the respective agreement.

For all properties, at the end of the contract life, title to all moveable and unmoveable assets, including all of the wells, facilities, infrastructure equipment, etc. associated with the fields and blocks and all lands, is returned to the applicable government along with the associated site restoration fund. Although the Company has exclusive right to use the equipment during the field life, the governments of the various countries are deemed to have title to the assets. Where income taxes are assessed, the Company is able to claim deductions for these assets.

India

The Company has an interest in two producing oil and natural gas blocks (the Hazira Field and the D6 Block) and one producing natural gas block (the Surat Block) in India. Production is sold to various industrial users. Natural gas is distributed via owned and non-owned pipelines, Hazira oil is trucked to the customer and D6 oil is produced into a FPSO. During Fiscal 2012, customers purchasing oil from India accounted for 19% of total Company revenue and natural gas production from India accounted for 65% of total Company revenue. During Fiscal 2011, customers purchasing oil and natural gas production from India accounted for approximately 17% and 69%, respectively, of total Company revenues. Markets and significant gas sales contracts and changes to contracts for individual properties, if any, are discussed in this section under "Hazira Field, India", "Surat Block, India" and "D6 Block, India".

There are also three non-producing blocks in India. See discussion in this section under "NEC-25, India", "Cauvery Block, India" and "D4 Block, India".

Hazira Field, India

Niko is the operator of the Hazira 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 on and offshore. In addition, Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area. Niko has constructed an offshore platform, an LBDP, a gas plant and an oil facility at the Hazira Field. The Company has one significant contract for the sale of natural gas from the Hazira Field at a price of $4.86/Mcf expiring April 30, 2016. The commitment for future physical deliveries of gas under this contract exceeds the expected related future production from the Company's total proved reserves from the Hazira Field estimated using forecast prices and costs. See "Legal Proceedings and Regulatory Actions – Proceedings in India – Hazira Field".

Surat Block, India

Niko holds, and is the operator of, a development area in the 24 square kilometre Surat Block located onshore adjacent to the Hazira Field in Gujarat State, India. The natural gas produced from the Surat Block is transferred to the customer via Niko's 6-inch pipeline to the customer's facility. The Company has a gas plant at the Surat Block. All of the production from the Surat Block is sold to one customer with a current price of $6.00/Mcf expiring March 31, 2013.

D6 Block, India

Niko has a 10% working interest in the D6 Block, with Reliance, the operator, holding a 60% interest and BP holding the remaining interest. The D6 Block is 7,645 square kilometres lying approximately 20 kilometres offshore of the east coast of India.

Production from the oil discovery in the MA field in the D6 Block commenced in September 2008 and commercial production commenced in May 2009. Six wells are on production and are tied into the FPSO, which stores the oil until it is sold on the spot market at a price based on Bonny Light and adjusted for quality.

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

The GOI has approved the pricing formula for the sale of gas from the D6 Block, which currently results in a gas price of $4.20/MMBtu (NHV). The Company signed numerous gas sales contracts with customers in the fertilizer, power, steel, city gas distribution, liquefied petroleum gas market and pipeline transportation industries, all of which contracts expire on March 31, 2014. There is a "take or pay" clause pursuant to which the customer must take 80% of the daily contracted quantity (calculated on a monthly basis). The gas price can be amended within the contract period based on a revised pricing formula approved by the GOI.

The Company calculates and remits profit petroleum expense to the GOI in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital and other expenditures made by the joint interest, which reduce the profit petroleum expense. There are costs that the Company has included in the profit petroleum calculations that have been contested by the GOI. See "Legal Proceedings and Regulatory Actions – Proceedings in India – D6 Block".

The profit petroleum calculation considers capital and other expenditures made by the joint interest, which reduce the profit petroleum expense. There are costs that the Company has included in the profit petroleum calculations that have been contested by the GOI. The Company's share of costs disallowed by the GOI for the years 2010-2011 and 2011-2012 amounts to $146.2 million. The Company's joint venture partner on the D6 Block has served notice of arbitration on the GOI. The Company believes that it is not determinable whether this issue will result in additional profit petroleum expense.

NEC-25, India

Niko has a 10% working interest in NEC-25, with Reliance, the operator, holding a 60% interest and BP holding the remaining interest. The remaining contract area comprises 9,461 square kilometres lying offshore adjacent to the east coast of India. Exploration and appraisal drilling has been conducted on the block and, once commerciality is declared, the Company expects to submit a development plan to the GOI.

Cauvery Block, India

The Company holds a 100% interest in the Cauvery Block, which is located onshore southeast India in the State of Tamil Nadu. The block is operated by the Company. The block covers 957 square kilometres and a total of 915 square kilometres of 3D seismic data have been acquired on the block. The Company has drilled four unsuccessful wells on this block. The estimated costs for the remaining well required under the Phase I work commitment is $2 million. The Company intends to relinquish the block.

D4 Block, India

Niko has a 15% participating interest in the D4 Block, with Reliance, the operator, holding a 55% interest and BP holding the remaining interest. The D4 Block is 17,050 square kilometres and lies offshore of the east coast of India in the Mahanadi Basin. Under Phase I commitments, 2,366 kilometres of 2D seismic and 3,600 square kilometres of 3D seismic have been acquired on the block. In addition, the Company, through Reliance (as operator), has a work commitment to drill three wells under Phase I. The Company and its partners have chosen to relinquish their respective interests in the

D4 Block. For the Company, this decision is the result of the most current geological assessment related to the size and risk of the trapping mechanism and the current commercial environment in India. The Company has paid estimated exit costs of $5 million to the GOI.

Terms of the Indian PSCs

Under the terms of the PSCs for the Hazira Field, the Surat Block and the two remaining 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.

(a) Hazira Field

In addition to the terms referred to under "Terms of the Various Agreements" in this section, the PSC for the Hazira Field provides:

(i) for a formula for sharing in the profit oil and gas produced from the field between the Company, its partner and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSC, 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%

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.

(ii) that the Company pay a royalty of 10% of the wellhead price for natural gas (which is reimbursed by the customers) and cess, which is an education tax in India, at the rate of 481 Indian rupees per metric tonne and 900 Indian rupees per metric tonne, respectively, for crude oil and condensate.

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

(b) Surat Block

In addition to the terms referred to under "Terms of the Various Agreements" in this section, the PSC for the Surat Block provides:

(i) 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 block. 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.

(ii) that the Company is required to pay a royalty of 12.5% of the wellhead value of crude oil and 10% of the wellhead value of natural gas, which is reimbursed by the customer;

(iii) 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 uncertainty in India regarding the applicability of this tax holiday to natural gas.

(iv) that, subject to earlier termination of the PSC, the PSC for the block expires when the license for the block expires.

(c) Offshore Blocks

In addition to the terms referred to under "Terms of the Various Agreements" above, the PSCs for the two offshore blocks in which Niko has retained an interest provide:

(i) 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. 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 and the D6 Block:

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

(ii) 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.

(iii) 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. In all cases, the Company can retain the development and discovery areas.

(iv) that the Company is required to pay a royalty to the GOI for offshore areas falling in water depth greater than four hundred metres of 5% of the wellhead value of crude oil and natural gas for the first seven years from the date of commencement of production in the field and 10% thereafter.

(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 uncertainty 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.

Bangladesh

In Bangladesh, the Company has an interest in one producing onshore natural gas field (Block 9) and two fields that are not producing (Feni and Chattak). During Fiscal 2012, one customer purchasing production from Bangladesh accounted for approximately 16% of total Company revenues in the consolidated financial statements and approximately 14% during Fiscal 2011. Distribution methods, significant gas sales contracts and changes to contracts, if any, are discussed in this section under "Block 9, Bangladesh". Production from Feni ceased in April 2010 and no reserves are reported for this property. Natural gas demand exceeds the current production levels in Bangladesh and, as a result, the Company is able to sell all of the Block 9 production to Petrobangla.

Chattak and Feni, Bangladesh

Feni covers 43 square kilometres and is located 6 kilometres west of the main natural gas line to Chittagong. Chattak covers 376 square kilometres and rights to this block were obtained in October 2003. The Company produced natural gas from Feni from November 2004 to April 2010. Pursuant to the JVA, the Company has rights to produce until October 2023 and this arrangement can be extended if production continues beyond such period. The Company was selling gas under a GPSA at a price of $1.75/Mcf, which GPSA expired in November 2009 and can be extended with mutual consent. The Company has proposed postponing extension of the GPSA pending resolution of the various claims raised against the Company as described under "Legal Proceedings and Regulatory Actions". Payment for the gas is being delayed as a result of such claims. On April 30, 2010, the Company suspended production from Feni claiming that Petrobangla's failure to pay for the natural gas already delivered has created a force majeure event under the JVA. See "Risk Factors – Bangladesh" and "Legal Proceedings and Regulatory Matters – Proceedings in Bangladesh".

Block 9, Bangladesh

The Company has a 60% interest in Block 9, which covers approximately 6,880 square kilometres of land in the central area of Bangladesh surrounding Dhaka. Three wells are currently producing from the block and there is a gas plant at the block.

The Company has signed a GPSA including a price of $2.34/MMbtu, which expires at the end of commercial production, at expiry of the PSC (March 31, 2026) or 25 years after approval of the field development plan (May 15, 2032). Petrobangla is the sole purchaser of natural gas production. The sales delivery point is at Niko's facility and thereafter is the responsibility of Petrobangla and is transported via its Trunk Pipeline.

The Block 9 PSC provides:

(a) a production period of 20 years for oil production and of 25 years for natural gas production.

(b) for the relinquishment of 25% of the block at the end of each of the initial exploration period and the first successive exploration period.

(c) 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 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 GOB is entitled to increase its share depending on the production level. At a natural gas production level up to 150 MMcf/d, the GOB is entitled to 61% of the profit natural gas during cost recovery and 66% of the profit natural gas after cost recovery.

(d) 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 $70 per metric tonne and a ceiling price, prior to 25% discount, of $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.

(e) 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).

(f) for the payment by the participants to Petrobangla of (i) production bonuses increasing from $1 million to $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 and (ii) contributions to research and development activities of Petrobangla equal to $0.03/bbl of the participant's share of profit oil, condensate and NGL production and $0.004/Mcf of the participant's share of profit natural gas (which amounts are not recoverable as costs).

Pakistan

Niko Resources (Pakistan) Limited holds and operates the Pakistan Blocks, which are located in the Arabian Sea near the city of Karachi and cover an area of 9,921 square kilometres. The Company has acquired 2,142 square kilometres of 3D seismic on the blocks.

The material provisions of the PSAs for the Pakistan Blocks include:

(a) 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.

(b) for the fixing of royalties payable to the GHPL at 0% of the value of petroleum produced for the first 48 months of commercial production, 5% for the next 12 months, 10% for the next 12 months and 12.5% thereafter.

(c) 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:

GHPL Entitlement		
< 4,000 Metres below sea level		
Cumulative production (MMbbl)	Crude Oil/LPG/ Condensate	Natural Gas
0 – 100	20%	10%
> 100 – 200	25%	15%
> 200 – 400	40%	35%
> 400 – 800	60%	50%
> 800 – 1200	70%	70%
>1200	80%	80%

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

GHPL Entitlement		
Ultra Deep Grid Areas		
Cumulative production (MMbbl)	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.

(d) for the Company to pay, to GHPL from the Company's profit oil and gas, any windfall price received for oil and gas sold as per a calculation specified in the PSA with reference to a base price of $24/bbl for crude oil and condensate and $2.50/MMBtu for natural gas increasing by $0.50/bbl and $0.10/MMBtu per year subsequent to approval of a development plan.

(e) for an initial term of five years with two renewal periods of two years each.

(f) 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; and Phase III includes a minimum work obligation of $3 million for each block in the fifth contract year.

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

(h) 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.

(i) that the Company, within 10 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.

(j) 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.

Kurdistan

Nikoresources (Kurdistan) Ltd. operates the Qara Dagh Block, which covers approximately 846 square kilometres onshore. A 2D seismic program has been acquired on the block and led to the selection of a drilling location. A well was drilled between May 2010 and October 2011. The Company's share of the estimated cost of the remaining work commitment for the exploration period is $6 million.

The KRG has a 20% interest in the Qara Dagh Block, the costs of which are borne proportionately among the remaining joint venture partners. The KRG assigned an additional 20% interest in September 2009 resulting in the Company acquiring an additional 10% interest and the Company's joint venture partner acquiring the other 10% interest. In July 2010, the Company acquired an additional 12% interest from Vast Exploration Inc. As a result, the Company currently holds a 49% interest and carries the proportionate cost for the KRG's interest, resulting in a 62% cost interest. The Company is able to recover the Company's costs and costs paid for the KRG's carried interest.

In addition to the provisions discussed above, the material provisions of the PSC for the Qara Dagh Block provide:

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

(b) for the KRG to have the right to review and approve natural gas sales contracts.

(c) for 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 an environment fund.

(d) for the fixing of royalties payable to the KRG at 10% of the value of petroleum produced.

(e) 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	32 – (17)*(IM – 1) (1.25)	>1 – 2.75	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.

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

(g) 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.

(h) 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 five years.

(i) that the Company is required to (A) 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, (B) relinquish 25% of the net area at the end of the first extension period, (C) relinquish all areas that are not production areas at the end of the exploration period.

Indonesia

The Company has interests in numerous PSCs for offshore Indonesian exploration blocks as indicated below:

Block Name	Offshore Area	Award Date	Working Interest	Area (Square Kilometres)
Bone Bay	Sulawesi SW	Nov. 2008	45%	4,969
South East Ganal(1)	Makassar Strait	Nov. 2008	100%	4,868
Seram(1)	Seram North	Nov. 2008	55%	4,991
South Matindok(1)	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri(1)	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Papua NW	May 2009	45%	4,991
Kofiau(1)	West Papua	May 2009	100%(2)	5,000
Kumawa	Papua SW	May 2009	45%	5,004
East Bula(1)	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau(1)	Papua W	Nov. 2009	51%(3)	4,926
North Makassar(1)	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV(1)	Papua SW	Nov. 2009	51%(3)	6,389
Cendrawasih Bay II	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III(1)	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV(1)	Papua NW	May 2010	50%	3,904
Sunda Strait I(1)	Sunda Strait	May 2010	100%	6,960
Obi	Maluku	Nov. 2011	51%(2)	8.057
North Ganal	Makassar Strait	Nov. 2011	31%	2,432
Halmahera II	West Papua	Dec. 2011	20%	6,000
South East Seram(1)	Maluku	Dec. 2011	100%	8,217
Lhokseumawe(4)	Nanggroe Aceh	Oct. 2005	30%	4,431

Notes:

(1) Operated by the Company.

(2) The Company has entered into farmout agreements that, subject to government approval, will reduce its working interests to 57.5% for the Kofiau Block and 42% for the Obi Block.

(3) The Company has entered into a farmout agreement for the West Papua IV Block and the Halmahera-Kofiau Block whereby the farmor has the option to obtain an additional working interest, subject to GRI approval, that would reduce the Company's working interest to 40%.

(4) In April 2012, the Company farmed-in to a PSC for the Lhokseumawe Block. See "Business of the Company – Recent Developments".

The Company has minimum work commitments to drill a total of 11 wells for the Indonesian blocks. The estimated costs to complete the remaining work commitments are: $5 million to be spent by May 2012; an additional $2 million to be spent by September 2012; an additional $60 million to be spent by November 2012; an additional $21 million to be spent by May 2013; an additional $1 million to be spent by November 2014; and an additional $3 million to be spent by December 2014. The Company has applied or plans to apply for extensions where drilling activity is planned. The Company expects to be granted approval from the GRI before the PSC three-year anniversary. The Company is required to relinquish a portion of the exploration acreage after the first exploration period.

The material terms of the PSCs for the Indonesian Blocks provide:

(a) for the right during the term of the PSC to freely lift, dispose of and export its share of petroleum, except as noted in (b) and (c) below, and retain abroad the proceeds obtained therefrom.

(b) for the supply of crude oil to the domestic market, commencing five years after first delivery of crude oil, in the amount of 25% of the contractors entitlement of crude oil produced at 25% of the weighted average price of crude sold during the year, which may be increased depending on the cost to produce.

(c) for the supply of natural gas to the domestic market in the amount of 25% of the quantity of natural gas proven reserves multiplied by the contractor's entitlement.

(d) for a term of 30 years, including an initial term of the exploration period of 6 years, extendable for a maximum period of four years.

(e) for the sharing in the profit petroleum among the participants and BPMIGAS; under the terms of the PSC, 80% of revenues can be used to recover costs; on the revenues not used to recover costs, BPMIGAS's share is as follows:

Profit Natural Gas	Profit Crude Oil
28.57%	37.5%

(f) that the Company is required to (i) relinquish 25% of the contract area after the first three contract years and an additional 15% if the firm commitment has not been completed, (ii) relinquish additional areas in excess of 20% of the original contract area before the end of the sixth contract year, and (iii) the entire contract area if exploration effort is not continued beyond the sixth contract year.

(g) work obligations for 2D seismic acquisition and drilling one exploratory well in the first three contract years and 3D seismic acquisition and processing and drilling exploratory well in the next three contract years;

(h) for production bonuses and other specified fees.

(i) for the obligation to offer a 10% participating interest in return for reimbursement of the 10% of costs incurred to a local government owned company or Indonesian national company at the time the first development plan is approved by the GRI.

Madagascar

In October 2008, Niko Resources (Overseas VIII) Limited farmed in on a PSC for a property located off the west coast of Madagascar covering an area of approximately 16,845 square kilometres. Niko Resources (Overseas VIII) Limited will earn a 75% participating interest in the Madagascar Block and any extension or renewal thereof or amendment thereto. The Company has work commitments for an exploration well and the Company's share of the remaining costs is estimated at $10 million of spending prior to September 2015.

<u>Terms of the Madagascar PSC</u>

The material terms of the PSC for the Madagascar Block provide:

(a) for an exploration phase covering a period of eight years, extendable up to two years if the total evaluation of the block is not completed and up to five years to carry out a feasibility study of a natural gas discovery with the approval of OMNIS.

(b) for an exploitation period for a commercial discovery of 25 years; in the event the commercial discovery is predominantly natural gas, the exploitation period will be 35 years; if commercial production is still possible at the end of the exploitation period, the Company can apply for a five-year extension with respect to oil production and a 10-year extension with respect to natural gas production.

(c) for the right to freely market natural gas from the block on terms approved by OMNIS, except as required to meet Madagascar domestic consumption requirements; the formula for fixing the natural gas price shall be established according to applicable Malagasy law having regard to the volume of sales, quality, distance to market and transport and distribution costs.

(d) for the sale of oil at the average of the FOB price per barrel, in U.S. dollars, obtained by the parties from the commercial sales of oil during the preceding month.

(e) for work obligations (i) for the first exploration phase, which expired September 2010 and was completed by the Company, an aeromag data acquisition of 25,000 line kilometres, 2,000 kilometres equivalent of 2D marine seismic, and acquisition of existing geological and geophysical data and interpreting the data acquired, (ii) for the second exploration phase, which expires September 2012, including a combination of 2D and 3D seismic and acquiring existing G&G data and interpreting of the same, and (iii) for the third exploration phase, which expires March 2014, the drilling one well to evaluate prospects.

(f) that the Company is required to (i) relinquish 50% of the contract area at the end of the second exploration phase and (ii) relinquish all areas that are not exploitation areas at the end of the third exploration phase.

(g) for the establishment of royalties payable to the government, which will be based on volumes extracted.

(h) for the sharing of the profit petroleum among the participants and OMNIS; under the terms of the PSC, 60% of revenues can be used to recover costs; on the revenues not used to recover costs, OMNIS's share escalates in accordance with the following:

Daily Production Natural Gas Increments	OMNIS Entitlement
Less than 20 MMCMD	10%
Equal to or > 20 MMCMD and < 50 MMCMD	16%
Equal to or > 50 MMCMD and less than 100 MMCMD	20%
Equal to or > 100 MMCMD	25%

Daily Production Liquid Petroleum Increments	OMNIS Entitlement
Less than 25,000 boe/d	10%
Equal to or > 25,000 boe/d and up to 50,000 boe/d	15%
Equal to or > 50,000 boe/d and up to 75,000 boe/d	25%
Equal to or > 75,000 boe/d and up to 100,000 boe/d	30%
Equal to or > 100,000 boe/d and up to 125,000 boe/d	35%
Equal to or > 125,000 and up to 150,000 boe/d	45%
Equal or > 150,000 boe/d	65%

(i) that the Company is subject to "Direct Tax on Petroleum", which discharges it from corporate income taxes, capital gains tax and withholding taxes on transfer; the "Direct Tax on Petroleum" is deemed to be included in the profit petroleum entitlement of OMNIS.

(j) for production bonuses, personnel and training expenditures for Malagasy nationals, and administration fees.

Trinidad and Tobago

As at the date hereof, the Company holds interests in nine PSCs and one exploration and production license for eight exploration areas. The chart below indicates the location of, the date of the PSC in respect of, the Company's working interest in and the size of the block/area.

Exploration Area	Location	PSC Date	Working Interest	Area (Square Kilometres)
Block 2AB[(1)]	Offshore	July 2009	37.75%	1,606
Guayaguayare Area – Shallow Horizon[(1)]	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare Area – Deep Horizon[(1)]	Onshore/Offshore	July 2009	80%	1,190
Central Range Area – Shallow Horizon	Onshore	September 2008	32.5%	734
Central Range Area – Deep Horizon	Onshore	September 2008	40%	856
Block 4(b)[(1)]	Offshore	April 2011	100%	753
Block NCMA 2[(1)]	Offshore	April 2011	56%	1,019
Block NCMA 3[(1)]	Offshore	April 2011	80%	2,106
Block 5(c)	Offshore	July 2005	25%	324
MG Block[(1)]	Offshore	July 2007	70%	223

Note:

(1) Operated by the Company.

The Company has minimum work commitments for the acquisition or reprocessing of seismic for the Trinidad Blocks and to drill a remaining total of 12 wells on such blocks. The estimated costs to complete the remaining work commitments are: $26 million to be spent by July 2013; an additional $18 million to be spent by September 2013; an additional $64 million to be spent by April 2014; an additional $20 million to be spent by July 2014; and an additional $54 million to be spent by April 2016. The work commitments related to Block 5(c) have been fulfilled.

The material provisions of the PSCs for the Trinidad Blocks include:

(a) for the pricing of crude oil at the international fair market value of crude oil adjusted for the different grades being produced and for the pricing of natural gas at the international fair market value, taking into account the quality, volume, cost of transportation, terms of payment and any other relevant conditions.

(b) for the recovery of costs incurred from revenue. Sixty percent of revenue can be used to recover costs for Block 2AB and the Guayaguayare Area. The percentages of revenue that may be used to recover costs for the Central Range Area and Block 5(c) range from 40% to 60% and from 40% to 65%, respectively, depending on the cumulative production in the block and the type of production. For Block 2AB, the Guayaguayare Area, the Central Range Area and Block 5(c), exploration costs may be recovered as they are expensed; development and production capital costs may be recovered over four years with 40% recoverable in the first year and 20% recoverable in each of the next three years; and operating and administrative costs are recovered in the year they are incurred. Fifty-five percent of crude oil revenue and 100% of natural gas revenue can be used to recover costs for Block NCMA 2, Block NCMA 3 and Block 4(b). There is no cost recovery in the MG Block, as the MG Block is operated under an exploration and production license under which a royalty is payable. Exploration, development, production capital and operating and administrative costs can be recovered in the year they are incurred.

(c) for a formula for sharing in the profit oil and gas produced from the blocks between the Company, the joint venture partners and the GTT on a monthly basis ranging from 30% to 63% based on production levels and the prices of crude oil and natural gas for Block 2AB, the Guayaguayare Area and the Central Range Area, 50% to 75% based on production levels and the prices of crude oil and natural gas for Block NCMA 2, Block NCMA 3 and Block 4(b) and 50% to 80% based on production levels and the prices of crude oil and natural gas for Block 5(c). Royalty rates in the MG Block are 2.5% on natural gas and crude oil.

(d) for an exploration period for Block 2AB of six contract years divided into a first phase of three years, an optional second phase of two years and an optional third phase of one year; for an exploration period for the Guayaguayare Area and the Central Range Area of six contract years divided into a first phase of four years, an optional second phase of one year and an optional third phase of one year; for an exploration period for Block NCMA 2 of six contract years divided into a first phase of five years, and optional second phase of six months and an optional third phase of six months; for an exploration period for Block NCMA 3 of six contract years divided into a first phase of three years, and optional second phase of two years and an optional third phase of one year; for an exploration period for Block 4(b) of six contract years divided into a first phase of three years, an optional second phase of two years and an optional third phase of one year; for an exploration period for Block 5(c) of six contract years divided into a first phase of three years and an optional second phase of three years; and for an exploration period for the MG Block of six contract years.

(e) that the Company is required under the first phase of the exploration period to acquire and process at least 864 square kilometres of 3D seismic and drill three wells, drill one well under the second phase of the exploration period and drill one well under the third phase of the exploration period for Block 2AB; that the Company is required under the first phase of the exploration period to acquire and process 100 kilometres of 2D seismic, acquire and process 168 square kilometres of 3D seismic and drill two wells, acquire and process 200 square kilometres of 3D seismic and drill two wells during the second phase of the exploration period and drill two wells during the third phase of the exploration period for the Central Range Area; that the Company is required to acquire and process 130 and 200 square kilometres of 3D seismic onshore and offshore, respectively, and drill two onshore wells and one offshore well during the first phase of the exploration period, drill one onshore well and one offshore well during the second phase of the exploration period and drill four onshore wells and one offshore well during the third phase of the exploration period for the Guayaguayare Area; that the Company is required under the first phase of the exploration period to acquire and process 1,000 square kilometres of 3D seismic and drill three wells, drill one well during the second phase of the exploration period and drill one well during the third phase of the exploration period for Block NCMA 2; that the Company is required under the first exploration period to acquire and process 1,500 square kilometres of 3D seismic and drill one well, drill one well under the second phase of the exploration period and drill one well under the third phase of the exploration period for Block NCMA 3; that the Company is required under the first exploration period to reprocess 1,000 square kilometres of 3D seismic and drill one well, drill one well under the second exploration period and drill one well under the third exploration period for Block 4(b); that the Company is required under the first exploration period to reprocess 324 square kilometres of seismic and drill three wells and under the optional second exploration period to reprocess and drill one well for Block 5(c); and that the Company is required to acquire and process 200 line kilometres of 2D seismic and drill one well for the MG Block.

(f) that the Company is required to (i) relinquish 25 to 40% of the block at the end of the first phase of the exploration period, (ii) cumulatively relinquish not less than 50% of the block by the end of the second phase of the exploration period except for Block 5(c), in which the remainder of the block, other than production, appraisal, natural gas discovery and specified exploration areas, must be relinquished, and (iii) relinquish all areas but the production, appraisal and discovery areas on or before the expiration of the exploration period.

(g) for the payment of various fees, including a hectare charge, an administrative charge, a training contribution, a research and development contribution, a technical assistance/equipment bonus, a signature bonus and production bonuses.

(h) for the payment of petroleum profits tax, an unemployment levy, a green fund levy and withholding tax arising out of income or profits derived from the conduct of petroleum operations for Block 2AB, the Guayaguayare Area, the Central Range Area and the MG Block. The payment of petroleum profits tax, an unemployment levy, a green fund levy and withholding tax arising out of income or profits derived from the conduct of petroleum operations shall be paid by the Minister of Trinidad and Tobago on behalf of the Company out of the GTT's share of profit petroleum for Block NCMA 2, Block NCMA 3, Block 4(b) and Block 5(c).

Canada

The Company has a 45% non-operated interest in the Cullen unit in Saskatchewan. It produced 38 bopd gross (17 bopd net) in Fiscal 2012 (Fiscal 2011 – 51 bopd gross (23 bopd net)).

Oil and Gas Wells

The following table summarizes the Company's interests in India and Bangladesh, as at March 31, 2012, in oil and gas wells:

Producing and Non-Producing Wells
As at March 31, 2012

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing(1)						
India – offshore	7.0	0.9	27.0	4.8	34.0	5.7
India – onshore	-	-	34.0	7.3	34.0	7.3
Bangladesh – onshore	-	-	4.0	2.4	4.0	2.4
Total Producing	7.0	0.9	65.0	14.5	72.0	15.5
Non-Producing(2)(3)						
India – offshore	1.0	0.1	1.0	0.3	2.0	0.4
India – onshore	-	-	-	-	-	-
Bangladesh – onshore	-	-	4.0	3.6	4.0	3.6
Total Non-Producing	1.0	0.1	5.0	3.9	6.0	4.0

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. Includes wells used for gas or water injection.

(3) Excludes a total of 51 gross (7.2 net) exploration wells that are not currently capable of production.

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, 2012				
	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2013 (Acres)	
Location	Gross	Net	Gross	Net
Bangladesh	1,795,383	1,116,503	424,300	254,580
India(1)(2)	8,576,828	1,280,991	5,549,596(1) (2)	978,268(1)(2)
Indonesia(3)	25,797,908	16,598,634	5,131,556(3)	3,509,334(3)
Kurdistan	208,962	102,391	-	-
Madagascar(4)	4,160,715	3,120,536	2,080,358(4)	1,560,268(4)
Pakistan	2,450,460	2,450,460	-	-
Trinidad	2,456,358	1,504,208	20,401	5,100
Total	45,446,613	26,173,723	13,206,210	6,307,550

Notes:

(1) The Company intends to relinquish the Cauvery Block and the entire 236,379 acres of the Cauvery Block are included above.

(2) The Company intends to relinquish the D4 Block and the entire 4,211,350 acres (631,826 acres net) of the D4 Block are included above.

(3) The Company has applied for or intends to apply for extensions to the exploration periods for acreage that will expire during the year. The Company expects to be granted approval from the GRI as applicable, before the PSC three-year anniversary.

(4) The Company applied for an extension for acreage expiring during the year and got the approval from OMNIS on June 14, 2012. However, the approval is subject to ratification by the PSC Management Committee.

For remaining work commitments on the unproven properties, see "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India", "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Bangladesh", "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Pakistan", "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Kurdistan", "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Indonesia", "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Madagascar" and "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – Trinidad and Tobago".

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 the D6 Block oil and gas developments are based on the costs included in the field development plans. The Company expects to incur these costs for 28 wells (net), 4 facilities (net), 0.3 pipelines (net), 0.3 LBDPs (net) and 0.4 offshore platforms (net), being all of the obligations for Fiscal 2012. The abandonment and reclamation costs related to the Block 9 are based on third party valuations as provided by the operator of the block. The amount of such costs expected to be incurred is $52 million ($23 million discounted at 10% per year). A total of $7 million of abandonment and reclamation costs ($3 million discounted at 10% per year) have not been deducted in estimating future net revenues under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data", as these costs are for properties for which no reserves have been attributed. The Company expects to pay $8 million for abandonment and reclamation costs within the next three fiscal years, which are primarily related to the Hazira Field and the Surat Block in India.

Costs Incurred

For Fiscal 2012, the Company incurred the following costs on its properties:

	MM$				
Country	Property Acquisition Costs		Exploration Costs	Development Costs	Total Costs
	Proved Properties	Unproved Properties[(1)]			
Bangladesh	-	-	1	2	3
India	-	-	7	19	26
Indonesia	-	3	67	-	70
Kurdistan	-	9	19	-	28
Madagascar	-	-	1	-	1
Pakistan	-	-	2	-	2
Trinidad and Tobago	78	18	113	1	210

Note:

(1) The Company considers signature bonuses required under the various PSCs to be property acquisition costs.

Exploration and Development Activities

For Fiscal 2012, the Company drilled the following exploration and development wells by country:

Exploration and Development Activities – India Year Ended March 31, 2012				
	Exploration Wells[(1)]		Development Wells	
Type	Gross	Net	Gross	Net
Oil	-	-	-	-
Gas	-	-	2.0	0.2
Service	-	-	-	-
Dry	-	-	-	-
Total	-	-	2.0	0.2

Exploration and Development Activities – Kurdistan Year Ended March 31, 2012				
	Exploration Wells[(1)]		Development Wells	
Type	Gross	Net	Gross	Net
Oil	1.0	0.6	-	-
Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total	1.0	0.6	-	-

Exploration and Development Activities – Trinidad and Tobago Year Ended March 31, 2012				
	Exploration Wells[1]		Development Wells	
Type	Gross	Net	Gross	Net
Oil	-	-	-	-
Gas	-	-	-	-
Service	-	-	-	-
Dry	3.0	1.0	-	-
Total	3.0	1.0	-	-

Note:

(1) Includes appraisal wells.

There were no wells drilled in Bangladesh, Pakistan, Indonesia, Madagascar or Canada during Fiscal 2012.

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 for Fiscal 2013 of the Company from its India properties and Bangladesh properties derived from the Ryder Scott Report for:

Estimated Production
Forecast Prices and Costs

	Proved Reserves (Gross)	Proved Reserves (Net)[1]	Probable Reserves (Gross)	Probable Reserves (Net)[1]
India, D6 Block Estimated production for the year ended March 31, 2013				
Natural Gas (MMcf)	34,726	34,378	438	434
NGL (Mbbl)	245	242	14	13
Light and Medium Crude Oil (Mbbl)	68	67	11	11
MMcfe	36,604	36,232	588	578

Estimated Production Forecast Prices and Costs				
	Proved Reserves (Gross)	Proved Reserves (Net)[1]	Probable Reserves (Gross)	Probable Reserves (Net)[1]
Bangladesh, Block 9 Estimated production for the year ended March 31, 2013				
Natural Gas (MMcf)	19,094	12,062	5,090	1,871
NGL (Mbbl)	62	39	16	6
Light and Medium Crude Oil (Mbbl)	-	-	-	-
MMcfe	19,466	12,296	5,186	1,907

Note:

(1) "Net" reserves are defined as those accruing to the Company's working interest share after royalty interests owned by others have been deducted. Royalty interests owned by others are comprised of profit petroleum amounts that will be payable to the GOI and the GOB.

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, 2012:

Average Daily Production Working Interest to the Company Year Ended March 31, 2012				
	Quarter Ended			
	June 30, 2011	September 30, 2011	December 31, 2011	March 31, 2012
India				
Oil (bbls/d)	1,594	1,669	1,278	1,461
NGL (bbls/d)	225	220	200	160
Gas (Mcf/d)	178,992	167,968	150,701	131,449
Mcfe/d – India	189,905	179,299	159,570	141,173
Bangladesh				
Oil (bbls/d)	-	-	-	-
NGL (bbls/d)	182	191	189	199
Gas (Mcf/d)	55,269	60,129	58,428	61,368
Mcfe/d – Bangladesh	56,359	61,276	59,559	62,559
Mcfe/d – Total	246,264	240,575	219,129	203,732

Netback History – India(1) Natural Gas Year Ended March 31, 2012				
	Quarter Ended			
	June 30, 2011	September 30, 2011	December 31, 2011	March 31, 2012
Average Price Received (US$/Mcf)	4.10	4.11	4.10	4.11
Royalties (US$/Mcf)(1)	(0.25)	(0.25)	(0.25)	(0.25)
Profit Petroleum (US$/Mcf)(1)	(0.11)	(0.08)	(0.13)	(0.10)
Production Costs (US$/Mcf)	(0.43)	(0.48)	(0.52)	(0.74)
Netback (US$/Mcf)	3.31	3.30	3.20	3.02

Netback History – Bangladesh(1) Natural Gas Year Ended March 31, 2012				
	Quarter Ended			
	June 30, 2011	September 30, 2011	December 31, 2011	March 31, 2012
Average Price Received (US$/Mcf)	2.31	2.30	2.32	2.32
Royalties (US$/Mcf)(1)	-	-	-	-
Profit Petroleum (US$/Mcf)(1)	(0.90)	(0.88)	(0.89)	(0.90)
Production Costs (US$/Mcf)	(0.41)	(0.29)	(0.42)	(0.24)
Netback (US$/Mcf)	1.00	1.13	1.01	1.18

Netback History – India[1] **Oil and NGL** **Year Ended March 31, 2012**				
	Quarter Ended			
	June 30, 2011	September 30, 2011	December 31, 2011	March 31, 2012
Average Price Received (US$/bbl)	113.41	108.69	101.57	113.11
Royalties (US$/bbl)[1]	(1.53)	(1.50)	(1.49)	(1.53)
Profit Petroleum (US$/bbl)[1]	(0.67)	(0.48)	(0.78)	(0.60)
Production Costs (US$/bbl)	(2.59)	(2.87)	(3.12)	(4.46)
Netback (US$/bbl)	108.62	103.83	96.18	106.53

Netback History – Bangladesh[1] **NGL** **Year Ended March 31, 2012**				
	Quarter Ended			
	June 30, 2011	September 30, 2011	December 31, 2011	March 31, 2012
Average Price Received (US$/bbl)	118.54	113.90	113.50	122.16
Royalties (US$/bbl)[1]	-	-	-	-
Profit Petroleum (US$/bbl)[1]	(5.38)	(5.30)	(5.35)	(5.41)
Production Costs (US$/bbl)	(2.45)	(1.73)	(2.49)	(1.45)
Netback (US$/bbl)	110.70	106.88	105.66	115.30

Note:

(1) Under the terms of the gas sales contracts that are in place with respect to Niko's natural gas production from Hazira and Surat India, 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 gas sales contracts that are currently in place with respect to the Company's natural gas production from the D6 Block in India, the purchasers of natural gas pay a marketing margin over and above the contracted price. Average price received as presented above is the contracted price plus the marketing fee plus the amount of royalties levied by the GOI. Under the terms of the applicable PSCs, the GOI and the GOB 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 GOB related to Bangladesh production.

The following table sets forth the Company's working interest sales volume by area for the Hazira Field, the Surat Block and the D6 Block in India and Block 9 and Feni in Bangladesh for Fiscal 2012, being the only properties from which there was production during that time:

Area	Light and Medium Crude Oil (bbls/d)	Natural Gas (Mcf/d)	NGL (bbls/d)	Total Natural Gas Equivalent (Mcfe)
D6 Block	1,351	149,443	201	158,755
Hazira Field	150	5,008	-	5,908
Surat Block	-	2,837	-	2,837
Total – India	1,501	157,288	201	167,500
Block 9	-	58,801	190	59,941
Total – Bangladesh	-	58,801	190	59,941
Total – Company(1)	1,501	216,089	391	227,441

Note:

(1) The Company total excludes the production relating to Canada, as such production comprises less than 0.05% of the Company's production for Fiscal 2012.

Definitions, Notes and Other Cautionary Statements

In the tables set forth in the Statement 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 or reserves, its working 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 or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, which are profit petroleum, plus the Company's royalty interests in production or reserves;

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

  (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.

- Definitions of Reserves:

Reserves 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.

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.

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 reserves categories (proved and probable) may be divided into developed and undeveloped categories:

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.

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.

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.

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:

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

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

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

(d) taking into account minimum alternative tax;

(e) taking into account the 80IB deduction with respect to natural gas and oil undertakings as determined by the Company; 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 bbl 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.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

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 15 years.	Chairman of the Board, President and Chief Executive Officer
Conrad P. Kathol[3][4][5][9] Alberta, Canada	Director	President of Silver Thorn Exploration Ltd. (a natural resource company) since April 2004.
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.
C. J. (Jim) Cummings[2][3][5] Alberta, Canada	Director	Partner of International Energy Counsel LLP (a law firm) since December 2002.
William T. Hornaday[4] Alberta, Canada	Chief Operating Officer and a Director	Chief Operating Officer of Niko Resources Ltd. since 2005. Prior thereto, Vice President, Operations of Niko.
Murray E. Hesje Alberta, Canada	Chief Financial Officer and Vice President 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 is a member 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. Hornaday is a member of the Environment and Reserves Committee.

(5) Mr. Cummings is the chairman and Mr. Kathol is a member 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), Mr. Cummings (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 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 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 TSX resumed on May 19, 2004.

As at the date hereof, the directors and executive officers of Niko, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 4,858,014 Common Shares constituting approximately 9.41% of the issued and outstanding Common Shares.

Orders

Other than as disclosed herein, to the knowledge of management of the Company, no director or executive officer is, 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 the Company's audit committee (the "**Audit Committee**") is to provide assistance to the board of directors of the Company 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 the Company, its independent auditors and its financial and senior management.

The full text of the Audit Committee's charter is included as Appendix "C" to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of Wendell W. Robinson and C. J. (Jim) Cummings. Wendell W. Robinson is the Chairman of the Audit Committee and the financial expert. Each of the members of the Audit Committee is financially literate under section 1.6 of NI 52-110 and each of the members is independent under section 1.4 of NI 52-110.

Relevant Education and Experience

Wendell W. Robinson is Senior Investment Partner and retired Managing Director, Global Environment Fund (an institutional investment management firm). Previously, Mr Robinson managed international private equity programs for Rockefeller & Co. During his 40 plus years of domestic and international financial, investment and company management, Mr. Robinson has been the director of numerous corporations, and a member of investment advisory boards and committees of investment entities throughout Southeast Asia, Europe, Latin American and the United States. Mr. Robinson has BA and MA degrees in Economics, with a minor in Finance, from Case Western Reserve University. Mr. Robinson is a Chartered Financial Analyst.

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.

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 Appendix "C" 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 2012 were CAD$778,500 (Fiscal 2011 – CAD$653,990).

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 2012 were CAD$52,500 (Fiscal 2011 – CAD$49,852).

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 2012 were CAD$39,500 (Fiscal 2011 – CAD$68,603).

All Other Fees

There were no other fees billed during Fiscal 2012 or Fiscal 2011 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.

DIVIDENDS

In June 2001, the Company implemented a policy of paying quarterly dividends on the Common Shares. The Company declared and paid a quarterly dividend of $0.03 per Common Share for each successive quarter to June 30, 2010 and has declared and paid a quarterly dividend of $0.06 per Common Share for each successive quarter thereafter. 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 and the financial condition of the Company.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. As at June 28, 2012, the Company had issued and outstanding 51,641,845 Common Shares and no other shares of any class. As at June 28, 2012, the Company had outstanding options to purchase 3,993,128 Common Shares.

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 in the capital of the Company 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.

Convertible Debentures

General

The Convertible Debentures were issued under the Debenture Indenture and are limited to an aggregate principal amount of CAD$310,000,000. The Convertible Debentures will mature and become due and payable on December 30, 2012 (the "**Stated Maturity Date**"), were issued in principal denominations of $100,000 or integral multiples thereof and bear interest at the rate of 5% per annum (after as well as before default or judgment, with interest on amounts in default at the same rate plus 2%), calculated semi-annually as of, and payable in arrears in equal semi-annual instalments on, January 1 and July 1 in each year.

Conversion Privilege

Each Debentureholder has the right, at any time prior to the close of business on the 60th day preceding the Stated Maturity Date, to convert all or, subject to certain restrictions, any portion of the principal amount outstanding under any Convertible Debentures held by it, in multiples of $100,000, into fully paid and non-assessable Common Shares at a conversion price of CAD$110.50 (subject to adjustment in accordance with the Debenture Indenture) (the "**Conversion Price**").

The Company has the right, at any time on or after December 30, 2011 and prior to the Conversion Date (as defined in the Debenture Indenture), to convert all of the Convertible Debentures into fully paid and non-assessable Common Shares at the Conversion Price in effect on the Conversion Date, exercisable by the Company giving notice in writing of the exercise of such right to the Debenture Trustee (as defined in the Debenture Indenture), provided that the exercise by the Company of such conversion right shall be conditional upon the volume weighted average trading price of the Common Shares on the TSX, for the period 21 consecutive trading days prior to the issuance of such notice by the Company and ending one day prior to the issuance of such notice by the Company, exceeding the Conversion Price by 30%.

Redemption

Subject to the early redemption right provided to the Debentureholders in certain circumstances, the Convertible Debentures are redeemable on but not before the Stated Maturity Date at a redemption price equal to the principal amount then outstanding of the Convertible Debentures to be redeemed, plus accrued and unpaid interest thereon, if any, up to but excluding the Stated Maturity Date.

Common Share Repayment Right

The Company has the right, in exchange for or in lieu of repaying the principal amount of the Convertible Debentures in money, to repay the principal amount of the Convertible Debentures, plus accrued interest thereon, by issuing and delivering to the Debentureholders, on the maturity date of such Convertible Debentures, freely tradeable Common Shares. The number of Common Shares to be issued upon the exercise of such right is to be calculated by dividing the principal amount of the Convertible Debentures, plus accrued interest thereon, by 94% of the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the third trading day preceding the maturity date of such Convertible Debentures.

Events of Default

The Debenture Indenture provides for customary events of default, including, among others: (a) failure of the Company to pay the principal payable on any Convertible Debenture when due; (b) failure of the Company to pay certain other obligations under the Debenture Indenture if such failure is not cured in accordance with the Debenture Indenture; (c) failure of the Company to observe or perform certain covenants or conditions contained in the Debenture Indenture on its part to be observed or performed and such failure is not cured in accordance with the Debenture Indenture; (d) certain events of bankruptcy, insolvency or reorganization with respect to the Company or any Guarantor or Material Subsidiary (as such terms are defined in the Debenture Indenture); and (e) proceedings are commenced for the winding-up, liquidation or dissolution of, or a resolution is passed for the winding-up or liquidation of, the Company or any Guarantor or Material Subsidiary (as such terms are defined in the Debenture Indenture), except as otherwise permitted under the Debenture Indenture. If an event of default has occurred and is continuing, then the Debenture Trustee (as defined in the Debenture Indenture) may, and shall upon receipt of written directions of Debentureholders having at least 25% of the aggregate principal amount of the Convertible Debentures then outstanding, declare the entire amount of the then outstanding obligations under the Debenture Indenture to be due and payable immediately, provided that such obligations shall become immediately due and payable without any declaration or other action by the Debenture Trustee or the Debentureholders if any one of certain events of default has occurred and is continuing.

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 in Canadian dollars for, and trading volume of, the Common Shares as reported by the TSX for the periods indicated:

	Trade Price (CAD$)		**Volume Traded**
	High	**Low**	**# of shares**
March 2012	47.52	33.62	6,073,422
February 2012	49.98	42.02	2,596,282
January 2012	55.00	46.51	1,647,299
December 2011	52.70	40.92	4,327,733
November 2011	57.71	47.33	2,449,511
October 2011	58.35	39.00	3,803,363
September 2011	56.50	40.95	2,695,465
August 2011	67.92	52.11	2,471,430
July 2011	69.99	59.35	1,833,744
June 2011	80.10	59.72	2,599,818
May 2011	80.29	70.55	3,122,232
April 2011	94.12	78.80	2,147,401

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. At the annual and special meeting of the holders of Common Shares held on September 11, 2008, the continued existence of the 2005 Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the 2005 Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2008 Rights Plan**") was executed. At the annual and special meeting of the holders of Common Shares held on September 21, 2011, the continued existence of the 2008 Rights Plan was approved and reconfirmed by the Independent Shareholders (as defined in the 2008 Rights Plan) and an amended and restated shareholder rights plan agreement (the "**2011 Rights Plan**") was executed. Its continued existence must be approved and reconfirmed by the Independent Shareholders (as defined in the 2011 Rights Plan) on or before the termination of the annual meeting of the shareholders of the Company held in the year 2014.

The following is a summary description of the general operation of the 2011 Rights Plan. This summary is qualified in its entirety by reference to the text of the 2011 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 2011 Rights Plan.

<u>Effective Date:</u> The 2011 Rights Plan is effective as of the close of business on August 9, 1999 (the "**Plan Effective Date**").

<u>Term:</u> The 2011 Rights Plan will expire at the termination of the annual meeting of shareholders in the year 2014. If the 2011 Rights Plan is reconfirmed by the holders of Common Shares at the annual meeting of shareholders held in the year 2014, it will expire at the termination of the annual meeting of shareholders in the year 2017.

<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 2011 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.

<u>Lock-Up Agreements:</u> 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 2011 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 2011 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 2011 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 2011 Rights Plan to maintain its validity due to changes in applicable legislation.

Exemptions for Investment Advisors: 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.

Board of Directors: The 2011 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.

Availability of Additional Reserves

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 natural gas reserves are 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 condition and/or results of operations and, accordingly, the trading price of the Common Shares, are likely to be materially affected.

International Operations

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 Canada, the United States and other jurisdictions affecting foreign trade, taxation and investment. For example, the Company may be at a disadvantage in that it may be required to compete against corporations or other entities from countries that are not subject to Canadian laws and regulations, including the CFPOA (or similar legislation of other jurisdictions, including the United States *Foreign Corrupt Practices Act*). Residents or nationals of countries not subject to such legal regimes may offer inducements to foreign governments and foreign public officials to entice such governments and officials to deal with them to the disadvantage of the Company. 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.

Emerging Markets

Investors in emerging markets should be aware that these markets are exposed to greater risk than developed markets, including significant political, economic and legal risks. Emerging economies are subject to rapid change and the information set out in this Annual Information Form may become outdated relatively quickly. Accordingly, investors should exercise particular care in evaluating the risks involved and must decide for themselves whether, in light of those risks, their investment is appropriate. Generally, investment in emerging markets is only suitable for sophisticated investors who fully appreciate the significance of the risks involved and who are prepared to lose some or all of their investment.

Exploration and Development

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.

Marketability of Oil and Natural Gas

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.

Fluctuating Prices

The prices that the Company will receive for its production and the levels of its production depend on numerous factors beyond its control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries (OPEC);
- the price and quantity of imports of foreign oil and natural gas;
- global economic conditions;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activities;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas; and
- the price and availability of alternative fuels.

Decreases in oil prices typically result in a reduction of the Company's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Company's reserves. Decreases in natural gas prices typically result in a reduction in the price at which the Company signs and renegotiates gas contracts and may result in a reduction of the Company's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Company's reserves. Any further substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Company's net production revenue, cash flows and profitability and have a material adverse effect on the Company's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities.

Infrastructure

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.

Reserves Estimates

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 reserves engineers may make different estimates of reserves quantities and the present value of net cash flows attributable to the production of such quantities. Substantial revisions to the reserves 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 reserves estimate. The reserves estimates included in this document could be materially different from the quantities and values ultimately realised.

Government Approvals

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. The Company's contractors and other counterparties who are subject to similar regulatory requirements may also delay or fail to obtain or maintain the necessary approvals, licenses, registration or permits. If any of these occurs, the Company or the sub-contractors or other counterparties that perform obligations for the Company may be subject to civil and administrative penalties, injunctions to limit or cease operations or suspension or revocation of permits, which could materially and adversely affect the Company's business, prospects, financial condition and results of operations.

The Company submits 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.

Cash Flow and Additional Funding Requirements

Based on the Company's forecasted cash and capital requirements over Fiscal 2013, the Company expects that its funds from operations and cash on hand will not be sufficient to meet all of its working capital requirements and planned capital expenditures in Fiscal 2013, and the Company will have to borrow funds or issue equity in order to meet its 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 the current holders of Common Shares, which dilution could be substantial.

Capital Markets

As a result of the weakened global economic situation, the Company, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Company's business has not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Company's ability to make such capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Company's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

If funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expenses related to development or maintenance of its existing properties, it will be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Issuance of Debt

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 the results of such exploration and development, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms.

Availability of Equipment

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.

Seismic Data

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures, as well as eventual hydrocarbon indicators, and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and the Company could incur losses as a result of such expenditures. As a result, some of the Company's drilling activities may not be successful or economical, and the Company's overall drilling success rate or its drilling success rate for activities in a particular area could decline, which could have a material adverse effect on expected results of operations and financial condition of the Company.

Credit Facilities

The Company is required to comply with covenants under its existing credit facilities. In the event that the Company does not comply with the covenants under its credit facilities, repayment could be required. The Company routinely reviews the covenants based on actual and forecast results and has the ability to adjust its development plans to comply with covenants under its credit facilities. Failure to comply with the covenants under its credit facilities could have a materially adverse effect on the Company.

Joint Ventures

The Company carries out a portion of its business through joint ventures and similar arrangements with third parties. These arrangements involve a number of risks, including:

- disputes with partners in connection with the performance of their obligations under the relevant joint operating agreements;
- disputes as to the scope of each party's responsibilities under such arrangements;
- financial difficulties encountered by partners affecting their ability to perform their obligations under the relevant joint operating agreement; and
- conflicts between the policies or objectives adopted by partners and those adopted by the Company.

In the event that the Company encounters any of the foregoing issues with respect to its joint operating partners, the Company's business, prospects, financial condition and results of operation may be materially and adversely affected.

Bangladesh

During Fiscal 2006, NRBL received a letter from Petrobangla demanding compensation related to the uncontrolled flow problems that occurred in Chattak in January and June 2005. Subsequent to March 31, 2008, NRBL was named as a defendant in a lawsuit that was filed in Bangladesh by Petrobangla and the Republic of Bangladesh demanding compensation as follows: (a) 42.28 Crore Taka ($5.3 million) for 3 Bcf of free natural gas delivered from Feni as compensation for the burnt natural gas; (b) 82.69 Crore Taka ($10.3 million) for 5.89 Bcf of free natural gas delivered from Feni as compensation for the subsurface loss; (c) 84.56 Crore Taka ($10.5 million) for environmental damages, an amount subject to be increased upon further assessment; (d) 634 Crore Taka ($78.8 million) for 45 Bcf of natural gas as compensation for further subsurface loss; and (e) any other claims that arise from time to time. The Company and the GOB had previously agreed to settle the GOB's claims through arbitration conducted in Bangladesh based upon international rules. The Company will actively defend itself against the lawsuit if it proceeds. This process could take in excess of five years. Service of the action has not been completed and NRBL has not filed a Statement of Defence. There is a risk that the Company will lose the lawsuit in the Bangladesh law courts. Any negative result to the Company and NRBL with respect to the above could have an adverse impact on the Company and its financial position. See "Legal Proceedings and Regulatory Actions – Proceedings in Bangladesh".

NRBL has taken steps to initiate two arbitrations with ICSID to resolve the claims in the Money Suit and the amounts owed to NRBL under the Feni GPSA. The ultimate resolution of those ICSID arbitrations and the timing of any such resolution are uncertain. Any negative result to the Company and NRBL could have a material adverse impact on the Company and its financial position. See "Legal Proceedings and Regulatory Actions – Proceedings in Bangladesh".

Legal Risks

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 (a) difficulty in obtaining 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, (b) a higher degree of discretion on the part of governmental authorities, (c) the lack of judicial or administrative guidance on interpreting applicable rules and regulations, (d) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions, or (e) 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.

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.

Operating Risks

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.

Oil and natural gas production operations are also subject to risks such as 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 adversely affect the Company's financial condition.

In addition, the Company is a joint venture partner in most of its fields and blocks 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.

Production

The majority of the Company's production comes from the D6 Block. The occurrence of any event that would prevent the production of natural gas or liquids from the D6 Block, 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, would have a significant adverse effect on the Company's cash flows and revenue until such time as such problem is remedied.

Dependence on Key Customers

The Company sells all of its production in Bangladesh to Petrobangla. This comprised 16% of total Company revenues for Fiscal 2012 compared to 14% for Fiscal 2011. If the Company were to lose Petrobangla as a customer, it could have a material adverse effect on the Company.

Taxation Risks

The Company has filed its income tax returns in India for the taxation years 1998 through 2008 under provisions that provide for a tax holiday deduction for production from the Hazira and Surat fields for eligible undertakings. The Company received a favourable ruling with respect to the tax holiday at the second appeal level for the taxation years 1999 through 2004. The Income Tax Department has filed an appeal against the orders and the matter is currently pending with the Indian court. The 2005 taxation year has been assessed at the first appeal level with favourable treatment with respect to the tax holiday and other deductions and the 2006, 2007 and 2008 taxation years are pending with the first level of appeal. The income tax returns for taxation years 2009, 2010 and 2011 have been filed including a deduction for the tax holiday but, unlike previous years, include only a single eligible undertaking per PSC. Should the Company fail through the legal process to receive a favourable ruling with respect to the tax holiday and the classification of eligible undertakings, the Company would record a tax expense of approximately $58 million, pay additional taxes of approximately $34 million and write off approximately $24 million of the income tax receivable. In addition, any failure could result in interest and penalties. 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.

Competition

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.

Dependence on Key Personnel

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.

Environmental Concerns

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.

Performance Guarantees

The Company has provided performance security guarantees to the governments of India and Indonesia totalling $14 million as at March 31, 2012. In addition, the Company has provided parent company guarantees on behalf of Niko Resources (Pakistan) Limited, Nikoresources (Kurdistan) Ltd., Niko Resources Trinidad & Tobago Ltd., Voyager Energy (Trinidad) Ltd., Niko Resources (NCMA2 Caribbean) Limited, Niko Resources (NCMA3 Caribbean) Limited and Niko Resources (Block 4b Caribbean) Limited to the governments from which the Company has obtained the exploration rights. In addition, the Company has provided parent company guarantees to one joint venture partner in Trinidad and Tobago and to number of contractors as provided for in various contracts. The recipients of the guarantees have the right to collect on the respective guarantees if the Company does not carry out the work commitments required under the various concession agreements (PSC or PSA) or as per the contracts signed by the Company.

Labour Concerns

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.

Foreign Currency

The majority of the Company's revenues and expenses are denominated in U.S. dollars. In addition, the Company converts any funds raised in Canadian dollars to U.S. dollars as required to fund forecast U.S. dollar expenditures. As a result, the Company has limited its cash exposure to fluctuations in the value of the U.S. dollar versus other currencies. However, the Company is exposed to changes in the value of the Indian rupee, Bangladeshi taka, Trinidad and Tobago dollar, Iraqi dinar, Indonesian rupiah, Malagasy ariary and Pakistani rupee versus the U.S. dollar as they are applied to the Company's working capital of its foreign subsidiaries. The financial instruments are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the cash and cash equivalents, accounts receivable, short-term investments, accounts payable, convertible debentures and borrowings of the Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar.

Conflicts of Interest

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".

Acquisitions of Properties

The Company has previously undertaken a number of acquisitions of assets. In addition, the Company's strategies include that, from time to time as suitable opportunities arise, the Company may consider acquiring additional oil and gas properties. Although the Company performs reviews of properties that the Company believes is consistent with industry practice prior to the acquisitions, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Company focuses its due diligence efforts on higher-valued properties or assets and conducts due diligence on only a sample of the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Physical inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. The Company may be required to assume pre-closing liabilities with respect to an acquisition, including environmental liabilities, and may acquire interests in properties on an "as is" basis. In addition, competition for the acquisition of prospective oil properties is intense, which may increase the cost of any potential acquisition. There can be no assurance that any potential acquisition by the Company will be successful.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Proceedings in Bangladesh

During Fiscal 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. The petitioners requested the following of the Supreme Court with respect to the Company:

(a) that the JVA be declared null and illegal;

(b) that the GOB realize from NRBL 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 NRBL relating to production from Feni (US$27.90 million as at March 31, 2012); and

(d) that all bank accounts of NRBL 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.

After a number of hearing dates over a long period of time, the Supreme Court delivered judgment on November 16 and 17, 2009, dismissing the proceeding on terms. The court:

(a) held that the JVA was not obtained by flawed process or by resorting to fraudulent means; the JVA was not declared null and illegal;

(b) noted that various committees formed by the GOB to assess the reasons for the blowouts and to assess the damages caused thereby concluded that NRBL was responsible for the blowouts;

(c) noted the claims pending in the Money Suit (as defined below) and stated that the amount of compensation should be decided by the court hearing that case after considering proper evidence or by mutual agreement among the parties; and

(d) continued the injunction and held that the GOB was restrained from making any payment to NRBL.

During Fiscal 2006, NRBL received a letter from Petrobangla demanding compensation related to the uncontrolled flow problems that occurred in Chattak 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 legal notice 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 JVA. 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 757 Crore Taka (approximately $95 million). The claimed losses were as follows: for gas burnt at Chattak – $5 million; for sub-surface loss at Chattak – $9 million; for environmental loss – 84.56 Crore Taka (approximately $11 million); and for additional sub-surface loss at Chattak – $70 million.

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 "**Money Suit**"). 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 was set for July 31, 2008 in Dhaka. There have been a number of court dates since then, but the proceedings have continually adjourned pending service of the pleading on all defendants. NRBL is consulting with its counsel with respect to its response to the Bangladesh action once service is properly effected. NRBL has not filed a Statement of Defence. The responses may include bringing an application to the Bangladesh court to stay the Money Suit on the grounds that the claims are properly the subject of arbitration agreements. The Company will actively defend NRBL against the lawsuit if it proceeds. This process could take in excess of five years. There can be no assurances as to the outcome of the lawsuit, or alternative arbitration, and the associated cost to the Company. Any negative result to NRBL could have an adverse impact on the Company and its financial position.

The Company remains of the view that NRBL has a good defence on the merits to the claims arising from the Chattak blowouts. It is also of the view that the claims ought to be resolved through international arbitration in accordance with the agreements between NRBL, Petrobangla and BAPEX.

On April 12, 2010, NRBL filed with the International Centre for Settlement of Investment Disputes ("**ICSID**") a request for arbitration against the GOB, BAPEX and Petrobangla. The request for registration was accepted by letter dated May 27, 2010 and a three-person panel was constituted on December 20, 2010.

The disputes to be arbitrated pursuant to NRBL's request are:

(a) all claims held jointly or severally by any of the GOB, BAPEX and Petrobangla arising from the blowouts at Chattak, including the claims raised in the pleadings filed in the Money Suit;

(b) whether NRBL is liable for any of those claims, in whole or in part, and if NRBL is liable, determination of the amount of its liability; and

(c) whether, in the case of BAPEX, it is obliged under the JVA to cooperate and agree with NRBL to commence arbitration proceedings with Petrobangla under the Feni GPSA and to terminate the Feni GPSA and shut in all production from Feni until such time as Petrobangla pays all amounts invoiced for gas delivered to Petrobangla under the GPSA and a new GPSA is made.

The Company and the GOB had previously agreed to settle the GOB's claims through arbitration conducted in Bangladesh. The Company's position is that BAPEX expressly agreed in the JVA to resolve disputes through international arbitration and that that agreement is binding on the GOB, which vested all of its interest in the subject properties in BAPEX.

On June 18, 2010, NRBL filed with ICSID a second request for arbitration against the GOB, BAPEX and Petrobangla. The request for arbitration was brought pursuant to the arbitration provisions of the Feni GPSA between NRBL, BAPEX and Petrobangla. The request for registration was accepted by letter dated July 28, 2010 and a three-person panel was constituted on December 20, 2010. The same panel has been constituted for both arbitrations.

The issues to be arbitrated pursuant to NRBL's request are:

(a) Petrobangla's failure or refusal to pay for gas delivered under the Feni GPSA from and after November 2, 2004;

(b) the validity of Petrobangla's alleged excuses for non-payment to the joint account established by NRBL and BAPEX for the purposes of receiving payments under the Feni GPSA;

(c) whether Petrobangla is entitled to any set-off on account of the claims raised in the pleadings filed in the Money Suit; and

(d) determination of the net amount owed by Petrobangla to NRBL (as the "Seller" under the Feni GPSA) pursuant to the Feni GPSA for gas delivered from and after November 2, 2004.

On February 14, 2011, the Chairman of the Tribunal held a preliminary procedural consultation with counsel for the parties, followed by the Joint First Session of the two Tribunals attended by counsel for the parties and all of the Tribunal members. The Tribunal adopted a procedural calendar to deal with the issues of jurisdiction. The procedural calendar sets out a number of steps and time deadlines with respect to the exchange of written submissions between April 1, 2011 and August 30, 2011, followed by an oral hearing on jurisdictional issues. That hearing took place from October 12 to 14, 2011 in London, England. The Tribunal reserved its decision and the decision has not yet been rendered. Any proceeding on the merits shall be determined only following the Tribunal's decision on jurisdiction.

The ultimate resolution of the ICSID arbitrations and the timing of any such resolution are uncertain. See "Risk Factors – Bangladesh".

Proceedings in India

Hazira Field

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

The Company may not be able to supply gas to a customer in the Hazira Field whose contract runs until mid 2016. The Company had previously planned to supply gas from the D6 Block to such customer. Due to a change in the gas allocation policy by the GOI, the Company may not be able to meet its obligations under the contract with gas supply from the D6 Block. The Company has notified the customer that the underperformance of the reservoir is a *force majeure* event. The customer does not agree with this position and has served a notice of arbitration on the Company. The matter is currently under judicial consideration in a court of law. In the absence of additional supply, the projected shortfall is 10.04 Bcf until the end of the contract. The Company believes that the outcome of this matter is not determinable at this time.

See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – Hazira Field, India".

D6 Block

The Company calculates and remits to the GOI its share of profit petroleum expense in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital and other expenditures made by the joint interest, which reduce the profit petroleum expense. There are costs that the Company has included in the profit petroleum calculations that have been contested by the GOI. The Company's share of costs disallowed by the GOI for the years 2010-2011 and 2011-2012 amounts to $146.2 million. The Company's joint venture partner on the D6 Block has served notice of arbitration on the GOI. The Company believes that it is not determinable whether this issue will result in additional profit petroleum expense. See "Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties – India – D6 Block, India".

Canadian Authorities Investigation

Following an investigation by Canadian authorities, on June 24, 2011, the Company pleaded guilty to a charge under the CFPOA in respect of improper payments made by the Company during 2005 to a Bangladesh public official. The Court of Queen's Bench of Alberta imposed a fine which has been paid and a Probation Order that requires the Company to strengthen its standards and practices to comply with the provisions of the CFPOA and other anticorruption laws and to provide annual reports of such compliance for a period of three years. The Company has retained the services of an independent audit firm to prepare the required compliance reports. See "Business of the Company – Three Year History".

Other than the foregoing or as otherwise disclosed herein, to the knowledge of management of the Company, there are no material legal proceedings to which the Company or to which any of its property is the subject, nor are any such proceedings contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, none of the directors or executive officers of the Company, any person or company that is a direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of outstanding voting securities of the Company, nor any associate or affiliate of the foregoing persons has had any material interest, direct or indirect, in any transactions during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Company.

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.

INTERESTS OF EXPERTS

The audited financial statements of Niko for Fiscal 2012 were audited by KPMG LLP, Chartered Accountants, of Calgary, Alberta. KPMG LLP has confirmed that it is independent of the Company in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

Ryder Scott prepared the Ryder Scott Report referred to in this Annual Information Form. 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 of the date hereof, the partners, employees and consultants of Ryder Scott who participated in or who were in a position to directly influence the preparation of the Ryder Scott Report own less than 1% of the securities of the Company.

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 August 24, 2011 for the annual and special meeting of the holders of Common Shares held on September 17, 2011. Additional financial information is also provided in the Company's financial statements and management's discussion and analysis for Fiscal 2012. 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

APPENDIX "A"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Terms to which meanings are 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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2012, 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%, included in the reserves data of the Company evaluated by us for the year ended March 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors.

Independent Qualified Reserves Evaluator	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) (US$000s)			
			Audited	Evaluated	Reviewed	Total
Ryder Scott Company	Estimate of Reserves and Future Income Report Prepared June 20, 2012	Bangladesh and India	N/A	742,004	N/A	742,004

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, consistently applied. 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.

Executed as to our report referred to above:

Ryder Scott Company-Canada, Calgary, Alberta, Canada

Execution Date: Dated as of the 20th day of June, 2012

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

APPENDIX "B"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which meanings are 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, 2012, estimated using forecast prices and costs.

An 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, 2012.

The Environment and Reserves 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 Reserves 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 Reserves 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) "Conrad P. Kathol"
Conrad P. Kathol
Director

Dated: June 27, 2012

APPENDIX "C"

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 shareholder 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.

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.