NIKO RESOURCES LTD

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED MARCH 31, 2013

July 8, 2013

Contents

Contents
(continued)

Page

ABBREVIATIONS AND DEFINITIONS

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

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

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;

"AJM Deloitte Report" means the independent reserves and economic evaluation of Niko's oil and natural gas interests in the D6 Block and NEC-25 in India and Block 5(c) in Trinidad and Tobago prepared by AJM Deloitte dated June 21, 2013 and effective March 31, 2013;

"**Aru Block**" means the contract area known as Aru located offshore to the south of West Papua, Indonesia as identified in a PSC entered into by Niko Resources (ARU) Limited, Statoil Aru AS and BPMIGAS in July, 2012;

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

"**BG Group**" means BG Group plc.

"**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., an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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;

"**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 Resources (Overseas XXII) Ltd., an indirect wholly-owned subsidiary of Niko, 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 Niko Resources (Overseas XXIII) Ltd., an indirect wholly-owned subsidiary of Niko, 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 Niko Resources (Overseas XXIV) Ltd., an indirect wholly-owned subsidiary of Niko, 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., an indirect wholly-owned subsidiary of Niko, 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;

"**COGE Handbook**" means Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

"**Concurrent Offering**" means the offering of the Company closed concurrently with the Public Offering in December 2012, of 5,882,350 common shares at CAD$8.50 per common share for approximately CAD$50 million to Maju Investments (Mauritius) Pte. Ltd.;

"**Convertible Notes**" means the note portion of the Public Offering, being CAD$115 million principal amount of convertible senior unsecured notes at a price of CAD$1,000 per note for aggregate gross proceeds of CAD$115 million;

"**Credit Agreement**" means the credit agreement between Niko and the lenders named therein, dated January 16, 2012, which provides Niko with revolving credit facilities;

"**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;

"**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, an indirect wholly-owned subsidiary of Niko, 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 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 ended March 31, 2013; "**Fiscal 2014**" means the fiscal year of the Company ending March 31, 2014; and **"Fiscal 2015"** means the fiscal year of the Company ending March 31, 2015;

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

"**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;

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

"**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., an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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;

"**Independent Shareholders**" means holders of voting shares other than: (i) any Acquiring Person; (ii) any offeror (other than any person who is deemed not to beneficially own the voting shares held by such person); (iii) any associate or affiliate of any Acquiring Person or offeror; (iv) any person acting jointly or in concert with any Acquiring Person or offeror; and (v) any employee benefit plan, deferred profit sharing plan, stock participation plan or trust for the benefit of employees of the Company or any subsidiary of the Company but excluding in any event a plan or trust in respect of which the employee directs the manner in which voting shares are to be voted and directs whether the voting shares are to be tendered to a take-over bid;

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

"**JCC**" or Japan Customs cleared crude, means the average price of customs cleared crude oil imports into Japan as reported in Trade Statistics announced by the Ministry of Finance, Japan;

"**June Offering**" means the private placement of the Company closed June 13, 2013, of US$63.5 million principal amount Unsecured Notes to a group of institutional investors for net proceeds of approximately US$58.5 million;

"**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, an indirect wholly-owned subsidiary of Niko, Black Gold Kofiau LLC and BPMIGAS in May 2009;

"**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, an indirect wholly-owned subsidiary of Niko, 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;

"**LNG**" means liquefied natural 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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., an indirect wholly-owned subsidiary of Niko, 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;

"**Public Offering**" means the public offering of the Company closed in December 2012, of (i) 12,688,000 common shares of the Company at CAD$8.50 per common share for gross proceeds of CAD$107.8 million and (ii)

CAD$115 million principal amount of Convertible Notes at a price of CAD$1,000 per Convertible Note for aggregate gross proceeds of CAD$222.8 million;

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

"**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 Block 9 prepared by Ryder Scott dated May 30, 2013 and effective March 31, 2013;

"**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, an indirect wholly-owned subsidiary of Niko, Black Gold Indonesia LLC, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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., an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, 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;

"**Tullow**" means Tullow Bangladesh Limited;

"**Unsecured Notes**" means US$63.5 million principal amount of 7% senior unsecured notes, issued pursuant to the June Offering;

"**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)(V) Limited, an indirect wholly-owned subsidiary of Niko, 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, an indirect wholly-owned subsidiary of Niko, Kaizan West Sageri LLC and BPMIGAS effective November 13, 2008.

Unless otherwise noted, all dollar amounts refer to US dollars.

INFORMATION CONCERNING RESERVES

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

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, 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.

"**Gross**" means:

- in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share before deduction of royalties and profit petroleum without including any royalty interest of the Company;
- in relation to wells, the total number of wells in which the Company has an interest; and
- in relation to properties, the total area of properties in which the Company has an interest.

"**Net**" means:

- 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;
- 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
- 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.

Reserves Categories

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 qualitative 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 estimates 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 actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative 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 are 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:

- making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes between oil and gas activities and other business activities;
- without deducting estimated future costs that are not deductible in computing taxable income;
- taking into account estimated tax credits and allowances;
- taking into account minimum alternative tax;
- taking into account the 80IB deduction with respect to natural gas and oil undertakings as determined by the Company; and
- 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.

Well and Cost Information

"**Development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic 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:

- 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;
- 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;
- 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
- 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:

- 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;
- 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;
- dry hole contributions and bottom hole contributions;
- costs of drilling and equipping exploratory wells; and
- 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.

Other Oil and Natural Gas Disclosure Matters

- Numbers may not add due to rounding.
- Estimated future abandonment and reclamation costs related to a property have been taken into account by Ryder Scott and AJM Deloitte 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 and AJM Deloitte were accepted by them as represented. No field inspection was conducted.

Future net revenues disclosed herein do not represent fair market value.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

Certain statements in this Annual Information Form are "forward-looking statements" or "forward-looking information" within the meaning of applicable securities laws. Forward-looking information is frequently characterized by words such as "plan," "expect," "project," "intend," "believe," "anticipate," "estimate," "scheduled," "potential" or other similar words, or statements that certain events or conditions "may," "should" or "could" occur. Forward-looking information is based on the Company's expectations and assumptions, including expectations and assumptions regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities, 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.

Such forward-looking information reflects the Company's current beliefs and assumptions and is based on information currently available to the Company. Since forward-looking statements address future events and conditions, by their very nature they involve inherent known and unknown risks and uncertainties. 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. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking information. These include, but are not limited to, the risks associated with the oil and natural gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation, the impact of general economic conditions, imprecision of reserve estimates, the lack of availability of qualified personnel or management, stock market volatility, the risks discussed under "Risk Factors" and elsewhere in this Annual Information Form and in the Company's public disclosure documents, and other factors, many of which are beyond the Company's control. Such forward-looking information is presented as of the date of this Annual Information Form, and the Company assumes no obligation to update or revise such information to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward-looking information, readers should not place undue reliance on this forward-looking information. See also "Risk Factors".

Specific forward-looking information contained in this Annual Information Form includes, among others, statements regarding:

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

- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws;
- capital expenditure programs;
- the Company's future development and exploration activities and the timing of these activities;
- the Company's future ability to satisfy certain contractual obligations;
- future economic conditions, including future interest rates;
- the impact of governmental controls, regulations and applicable royalty rates on the Company's operations;
- the Company's expectations regarding the development and production potential of its properties;
- the Company's expectations regarding the costs for development activities;
- the resolution of various legal claims against the Company;
- the potential for asset impairment and recoverable amounts of such assets; and
- changes to accounting estimates and accounting policies.

Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

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

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

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

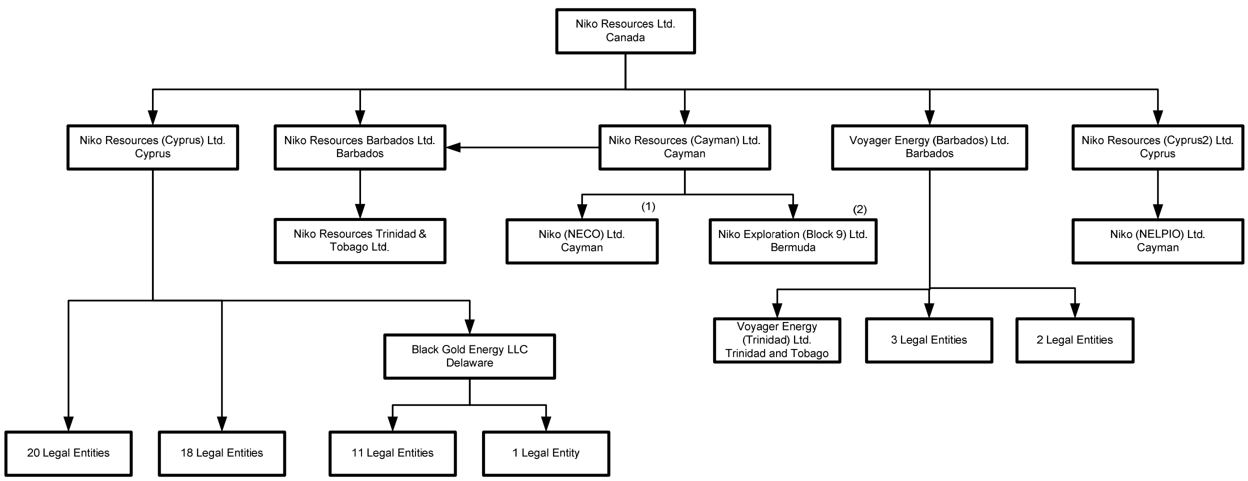
The Company discloses the nature and timing of expected future events based on its budgets, plans, intentions and expected future events for operated properties. The nature and timing of expected future events for non-operated properties are based on budgets and other communications received from joint venture partners.

The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

THE COMPANY

Niko was incorporated under the ABCA on March 26, 1987. On October 7, 1997, the Company's Articles of Incorporation were amended to delete the class A shares and class B shares, to rename the common shares and to create a class of preferred shares. Niko's principal and registered office is located at Suite 4600, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

With certain exceptions, the Company's subsidiaries hold substantially all of its assets. The following diagram describes the intercorporate relationships among the Company and its subsidiaries, which are all wholly-owned. Subsidiaries accounting for less than 10 percent of the Company's consolidated assets and revenues and in aggregate accounted for less than 20 percent of the Company's consolidated assets and revenues at March 31, 2013 have been excluded from the diagram below.



(1) Niko (NECO) Limited holds our interest in the D6 Block in India.
(2) Niko Exploration (Block 9) Limited holds our interest in Block 9 in Bangladesh.

BUSINESS OF THE COMPANY

General

Niko is a Canadian-based international company engaged in the exploration for, and the development and production of, natural gas and crude oil. It currently holds interests in: (i) producing assets in India and Bangladesh, (ii) development opportunities in India and Trinidad and Tobago and (iii) exploration acreage in India, Indonesia, Trinidad and Tobago, Madagascar and Pakistan. It also has minor interests in oil and gas properties in Canada. For further information on individual properties, see "Assets". The Company's common shares are listed on the TSX under the symbol "NKO".

Substantially all of Niko's current reserves are located in the D6 Block and NEC-25 in India, Block 9 in Bangladesh and Block 5(c) in Trinidad and Tobago and substantially all of Niko's current production is from the D6 Block in India and Block 9 Bangladesh.

Company Gross Reserves Forecast Prices and Costs as at March 31, 2013		
	Gross Proved (Bcfe)	Gross Proved plus Probable (Bcfe)
India	266	436
Bangladesh	101	150
Trinidad and Tobago	197	235
Total	564	821

As at March 31, 2013, the Company's proved reserves increased by 166% compared to March 31, 2012 balances, a proved reserve replacement ratio of over 700%, and the Company's proved plus probable reserves increased by 118%, a proved plus probable reserve replacement ratio of nearly 900%.

India

For the D1, D3 and MA producing fields in the D6 Block, virtually no revisions were reflected for combined proved reserves on a gas equivalent basis, with small positive revisions reflected for combined proved plus probable reserves. A combined total of 165 Bcf of proved and 270 Bcf of proved plus probable reserves additions were booked for the R-Series and Satellite Area development projects in the D6 Block and the J-Series development project in NEC-25.

Bangladesh

Positive revisions to proved reserves of 46 Bcfe were reflected for Block 9, increasing proved reserves to 101 Bcfe even after production of 20 Bcfe.

Trinidad and Tobago

For the Endeavour/Bounty development project in Block 5(c), additions to proved reserves were 197 Bcf (235 Bcf on a proved plus probable basis).

History

Founded in 1987, Niko's first six years of operation were confined to the Western Canadian Sedimentary Basin where the Company drilled and participated in wells in Alberta and southern Saskatchewan. In 1993, Niko made the decision to focus on international opportunities, starting with India. Over time, Niko became a significant participant in the Indian oil and gas sector, shaping its overall business strategy of focusing on high-impact plays and providing the foundation that has enabled the Company to expand its portfolio of international producing, development and exploration assets. The Company diversified and expanded its portfolio to include interests in Indonesia and Trinidad and Tobago over the past five years to become one of the largest non-state-owned exploration acreage holders in these countries.

The following is a description of events and conditions that have influenced the general development of the Company over the past three years.

India

The Company has held interests in India since 1994. Niko began a multi-well exploration program on the D6 Block in 2002 and on NEC-25 in 2003. The Company announced its first discovery of a major gas-bearing formation in the D6 Block in late 2002. In June 2004, the Company announced three new discoveries on NEC-25.

The Company added to the producing assets in its portfolio when commercial production started from the MA oil field and the Dhirubhai 1 and 3 natural gas fields in the D6 Block in May 2009. Niko, together with its partners, have signed numerous gas sales contracts with customers in various industries for the supply of natural gas from the D6 Block, each with an expiry date of March 31, 2014.

In January 2012, the GOI approved the optimized field development plan for the Satellite Discoveries in the D6 Block.

In May 2012, the Company relinquished its interest in the D4 Block, an offshore exploration area northeast of the D6 Block, based on the most current geological assessment related to the size and risk of the trapping mechanism and current commercial environment in India. Niko's partners, Reliance (operator) and BP also relinquished their interests.

In June 2012, based on performance of the Dhirubhai 1 and 3 natural gas fields and a revised geological model, Niko reported a significant downward revision to its reported reserves associated with these fields in the D6 Block. This revision was reflected in the report prepared by Ryder Scott having an effective date of March 31, 2012.

In January 2013, the field development plan for the R Cluster gas fields in the D6 Block was submitted to the GOI for approval and in March 2013, the integrated block development plan for NEC-25 was submitted to the GOI for approval.

In May 2013, the Company, along with its partners Reliance and BP, announced a significant gas and condensate discovery in the MJ-1 well in the D6 Block, which is expected to add to the hydrocarbon resources in the D6 Block. Appraisal is expected to commence later in 2013 to better define the scale and quality of the field.

Bangladesh

The Company initiated efforts in 1997 to identify and secure oil and gas opportunities in Bangladesh. In 2003 Niko entered into a joint venture with BAPEX in respect of the Chattak and Feni gas fields and acquired a 60% interest in Block 9. Natural gas production from the Block 9 field in Bangladesh commenced in May 2006 and commerciality was declared in December 2006.

In June 2011, the Company pleaded guilty to one count of bribery under the CFPOA in respect of two specific incidents that occurred in Bangladesh in 2005. See "Legal Proceedings and Regulatory Actions - Proceedings in Canada - CFPOA" and "Risk Factors".

Indonesia

In October 2008, the Company signed PSCs with the GRI for its first blocks in Indonesia and over the course of the following four years, expanded its position in Indonesia to 22 blocks covering 29.4 million gross acres. The Company acquired the acreage by successfully bidding for blocks, by way of farm-in into other blocks and through acquisitions.

In December 2009, the Company acquired all of the outstanding shares of Black Gold Energy LLC through one of Niko's wholly-owned subsidiaries, Niko Resources (Cyprus) Limited, for a purchase price of $300 million. This acquisition increased the Company's working interest in its Indonesian Blocks. To help finance this acquisition, the Company issued CAD$310 million aggregate principal amount of 5 percent convertible debentures. The convertible debentures had a conversion price of CAD$110.50 per common share and matured on December 30, 2012. The convertible debentures were repaid in December 2012 with the proceeds of the Public Offering, the Concurrent Offering and an advance under the Company's Credit Agreement.

From 2009 to 2012, the Company used its proprietary SeaSeep™ high resolution multi-beam data collection and analysis, sub-sea coring, and 2D and 3D seismic to develop an inventory of numerous high impact exploration prospects in Indonesia. Over this period, industry partners such as Statoil, Repsol, Hess, GDF Suez and ENI signed farm-in agreements to carry a disproportionate share of exploration costs associated with the Company's PSCs in return for portions of Niko's interests in its blocks, significantly reducing Niko's cost of exploration.

In November 2011, the Company signed a contract for the Ocean Monarch deepwater semi-submersible rig. The term of the contract is for four years, commencing October 2012, with an option of one additional year. The Company plans to utilize this rig to drill exploration prospects in its diverse and extensive exploration portfolio in Indonesia. Pursuant to the terms of the contract, the Company has the right to assign the rig to third parties.

In April 2012, in the Lhokseumawe Block, the jack-up rig used for two shallow-water wells experienced mechanical problems and none of the three wells encountered commercial quantities of hydrocarbons. The primary objective of each of these wells was not evaluated. A deepwater well drilled in the block did not encounter commercial hydrocarbons and the Company has relinquished its interest in the block.

In March 2013, the Cikar-1 well in the West Papua IV block was drilled and temporarily suspended due to well conditions after encouraging initial results.

During Fiscal 2013, three potential discoveries were made in Indonesia. In September 2012, the Lebah-1 well, located on the North Ganal PSC penetrated net pay in a secondary target zone and the joint venture partners are finalizing plans to drill an appraisal well. In January 2013, the Company drilled the Ajek-1 well in the Kofiau Block, which was assessed as a sub-commercial oil and gas discovery.

In June 2013, the Pananda-1 exploration well in the North Makassar Block identified an 80 foot gas interval in the upper section of the well and confirmed the presence of hydrocarbons in a previously untested Middle Miocene turbidite package in a basin floor setting. Poor reservoir properties indicate non-commerciality at this location.

Trinidad and Tobago

In July 2009, the Company signed a PSC with the GTT for its first block in Trinidad and Tobago and over the course of the following three years, expanded its position in Trinidad and Tobago to nine exploration areas and one development area, covering 2.4 million gross acres. The Company acquired the acreage by successfully bidding for blocks and through acquisitions.

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

In June 2011, the Company acquired a 25 percent interest in Block 5(c), which includes the Bounty, Endeavour and Victory discoveries, for a total cost of $78 million.

In October 2011, the field development plan for the Bounty and Endeavour fields was submitted to the GTT for approval.

In November 2011, the Company commenced its Trinidad and Tobago drilling campaign. Three offshore wells drilled in Block 2AB were not successful and the Company has applied to the GTT to relinquish the block. Two unsuccessful wells were also drilled in the Central Range Area.

Recent Developments

In June 2013, the Company completed a private placement of US$63.5 million principal amount of Unsecured Notes to a group of institutional investors. The Unsecured Notes bear interest at 7 percent per annum, payable monthly, and will be repaid through twelve equal monthly principal payments commencing August 13, 2013. Principal and interest payments are payable in cash or, at the option of the Company, in Common Shares of Niko. If the Company elects to make any portion of a payment in Common Shares, the number of Common Shares to be issued will be determined by dividing the amount to be paid in Common Shares by 94.5 percent of the lower of the volume weighted average price of the shares for the 15 day period prior to the payment date and the volume weighted average price of the Common Shares for the five day period prior to the payment date, subject to certain restrictions. To the extent that the applicable price determined under the above formula is less than 85 percent of the volume weighted average price of the Common Shares for the five day period prior to the payment date then, in lieu of delivering Common Shares, the Company will make a cash payment to the holders of the Unsecured Notes. The net proceeds of the June Offering were approximately US$58.5 million, after deducting the initial purchasers' discount and the estimated related expenses payable by Niko. Under the terms of the Unsecured Notes, the net proceeds can be used for general corporate purposes. Additional details regarding the terms of the Unsecured Notes are contained in the material change report of the Company dated June 24, 2013, a copy of which is available at www.sedar.com.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Niko actively competes 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, 2013, Niko had 26 employees at its head office in Calgary, 77 employees at its India offices, 18 employees at its Bangladesh office, one employee at its Pakistan office, three employees at its Madagascar office, 24 employees at its Trinidad and Tobago offices, 126 employees at its Indonesia offices and 5 employees at its Brazil office.

ASSETS

Niko's diversified portfolio of producing, development and exploration assets is described below. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Producing Assets

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

D6 Block, India

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

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

Production from the crude oil discovery in the MA field commenced in September 2008 and commercial production commenced in May 2009. Six wells are tied into a FPSO, which stores the crude oil until it is sold on the spot market at a price based on the Bonny Light reference price and adjusted for quality, and four of these wells are currently on production. In Fiscal 2014, the joint venture plans to drill an additional gas development well and convert one of the two suspended oil wells into a gas producing well to accelerate the production of the reservoir's gas reserves.

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

Production from the Dhirubhai 1 and 3 fields peaked in March 2010 and has decreased since then, primarily due to natural declines of the fields and greater than anticipated water production. Four additional wells have been drilled in the post-production phase of drilling. Based on the information obtained from three wells drilled within the main channel fairway, the Company has determined that it is not economic to tie-in any of these three wells at the present time. The fourth well was drilled outside of the main channel fairway and did not encounter economic quantities of natural gas. Nine of the original 18 wells are currently shut-in and several others are choked, primarily due to current constraints in water handling capacity. Workovers are planned to bring some of the shut-in wells back online during fiscal 2014. Increased water handling capacity and additional booster compression is expected to be installed over the next two years to address the decline in reservoir pressure.

The PSC for the D6 Block states that natural gas must be sold at arm's length prices, with "arm's length" defined as sales made freely in the open market between willing and unrelated sellers and buyers, and that the pricing formula be approved by the GOI taking into account the prevailing policy on natural gas. In May 2007, Reliance, on behalf of the joint venture partners, discovered an arm's length price for the sale of gas on a transparent basis with a term of three years and accordingly, proposed a gas price formula to the GOI. In September 2007, the GOI approved a pricing formula with some modification to the proposed formula. As a result of these modifications, the gas price is capped at $4.20/MMBtu and the formula was declared effective for a period of five years rather than the three years proposed by Reliance. The Company has signed numerous gas sales contracts with customers in the fertilizer, power, steel, city gas distribution, liquefied petroleum gas market and pipeline transportation industries, and all of these contracts expire on March 31, 2014. In June 2013, the Cabinet Committee of Economic Affairs of the GOI approved a new pricing formula for domestic gas sales in India, based on the recommendations of the Rangarajan Committee. The pricing formula is based on the average of the prices of imported LNG into India and the weighted average of gas prices in North America, Europe and Japan, as follows:

- $P_{AV} = \{P_{IAV} + P_{WAV}\} / 2$
  - P_{AV} = Sales price for domestic natural gas sales in India
  - P_{IAV} = Netback price of Indian LNG term imports (excluding spot imports)
  - P_{WAV} = Weighted average of prevailing gas prices in global markets, based on:
    - Henry Hub gas price in U.S. and total volumes consumed in North America
    - National Balancing Point gas price in U.K. and total volume consumed in Europe and Eurasia
    - Netback price of Japanese LNG imports and total volume imported by Japan

The pricing formula will be effective on April 1, 2014 for a period of five years, with the price to be revised quarterly using the approved formula. The price for each quarter will be calculated based on the 12 month trailing average price with a lag of one quarter (i.e., the price for April to June 2014 will be calculated based on the averages for the 12 months ended December 31, 2013). At the present time, the Indian LNG term imports relate primarily to the Petronet contract with RasGas of Qatar. Per the Rangarajan Committee Report, the pricing terms of this contract are as follows:

- FOB $= P_o \times JCC_t / \$15$
  - P_o = \$1.90 / MMBTU (therefore, FOB = 12.67% x JCC_t)
  - JCC_t = 12 trailing month average JCC price, subject to a floor and ceiling:
    - Floor = {(60 – N) x \$20 + (N x A60)} / 60 - \$4
    - Ceiling = {(60 – N) x \$20 + (N x A60)} / 60 + \$4
      - N = 1 for January 2009, increasing by 1 every month until December 2013 after which it remains at 60
      - A60 = 60 trailing month average price of JCC

In the future, the Indian LNG term imports are expected to include imports related to the Petronet contract with ExxonMobil for import of LNG from the Gorgon venture in Australia. Per the Rangarajan Committee Report, the terms of this contract are as follows:

- FOB = 14.5% x JCC

Estimated liquefaction and transportation costs of $3.00/MMbtu for older LNG facilities (pre-2010) or $4.00/MMbtu for newer LNG facilities are to be deducted to arrive at the netback price for Indian LNG term imports.

Using the approved price formula, the price effective for April 1, 2014 is estimated at around $8.40/MMbtu, double the price of $4.20/MMbtu for current gas sales from the D6 Block. The pricing terms of the Petronet contracts are expected to result in further increases in the gas prices in future quarters, assuming current pricing levels of JCC, U.S. Henry Hub, U.K. National Balancing Point and Japan LNG imports.

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

The Company calculates and remits the government share of profit petroleum to the GOI in accordance with the PSC for the D6 Block. The profit petroleum calculation considers capital, operating and other expenditures made by the joint venture. Because there are unrecovered costs to date, the GOI's share of profit petroleum has amounted to the minimum level of one percent of gross revenue. The government share of profit petroleum will increase above the minimum level once past unrecovered costs have been fully recovered. The Company has included certain costs in the profit petroleum calculations that are being contested by the GOI and has received notice from the GOI making allegations in relation to the fulfillment of certain obligations under the PSC for the D6 Block. Refer to note 14 to the consolidated financial statements for nine months ended March 31, 2013 for a complete discussion of this contingency.

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

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

Block 9, Bangladesh

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

The Company's share of production from the Bangora field reached a sustained rate of production of 60 MMcf/d in 2009. The Company expects to add compression at the gas processing plant in the fourth quarter of Fiscal 2014 which will allow sustained production levels through 2015. The Company has signed a GPSA including a price of $2.34/MMBtu (or $2.34/Mcf), which expires at the earliest of the end of commercial production, at expiry of the PSC (March 31, 2026) and 25 years after approval of the field development plan (May 15, 2032). Petrobangla is the sole purchaser of the natural gas production from this field. The sales delivery point is at the Company's facility and thereafter is the responsibility of Petrobangla and is transported via Trunk Pipeline.

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

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

Under the terms of the Block 9 PSC, income tax is deemed to be included in the government share of profit petroleum.

Planned Developments

The Company has undeveloped discoveries in the D6 and NEC-25 blocks in India and in Block 5(c) in Trinidad and Tobago. Based on development plan submissions, increased clarity on future gas prices and positive project economics for the developments, the Company booked significant proved and probable reserves for these projects, effective March 31, 2013. The developments will provide the opportunity for significant production growth for the Company in the next four to six years.

The following is a brief description of these development plans.

Additional Areas, D6 Block, India

The Company's exploration program has identified three additional areas in the D6 Block for potential future development. In January 2013, the G2 well on the D19 discovery, one of four satellite discoveries approved for development by the GOI in January 2012, was successfully drilled and the development plan for the R Cluster gas fields was submitted to the GOI for approval. The development of these areas is expected to be completed within four years after the approval of the development plans. The plans include the re-entry and completion of certain existing wells and the drilling of new wells, all connected with new flow-lines and other facilities into existing D6 Block infrastructure.

NEC-25 Block, India

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

Block 5(c), Trinidad and Tobago

The Company has a 25 percent working interest in Block 5(c) with the BG Group, the operator, holding the remaining 75 percent working interest in this offshore development area that covers 241 square kilometres. In October 2011, the BG Group submitted a development plan to the GTT for approval. Development of natural gas production from two discovered fields in the block is expected to require the drilling of new wells, construction of new flow-lines and other facilities, and expansion of an existing platform in the adjacent Block 6(b) operated by the BG Group.

Exploration Discoveries

Discovery: MG-1, D6 Block, India

In March 2013, after a multi-year hiatus, exploration drilling recommenced in the D6 Block in India with the drilling of the MJ-1 exploration well. In May 2013, the joint venture partners announced a significant gas and condensate discovery. The MJ-1 well was drilled in a water depth of 1,024 metres - and to a total depth of 4,509 metres - to explore the prospectivity of a Mesozoic Synrift Clastic reservoir lying over 2,000 metres below the already producing reservoirs in the D1- D3 gas fields. Formation evaluation indicates a gross gas and condensate column in the well of about 155 metres in the Mesozoic reservoirs. In the drill stem test, the well flowed 30.6 MMcf/d of natural gas and 2,121 bbls/d of liquids though a choke of 36/64", with a flowing bottom hole pressure of 8461 psia suggesting good flow potential. Well flow rates during such tests are limited by the rig and well test equipment configuration. The discovery, named 'D-55', has been notified to the GOI and the Management Committee of the block.

Subsequent to the completion of drilling operations, a preliminary technical evaluation has been conducted that has incorporated all seismic and new well data. Principal findings demonstrate that most parameters for the MJ reservoir exceed the high end pre-drill estimates. In particular, MJ-1 has considerable thicker reservoir pay than the best case pre-drill assessment. The fully cored MJ-1 pay interval was found to be 95% sand bearing with net pay averaging 125 metres. In addition, the MJ-1 gas water contact, as confirmed by wireline log and MDT data, is at the equivalent depth of a mapped seismic flat spot and a northern structural spill point. This validates that MJ is filled fully to structural spill and accordingly aligns the MJ field nearer the maximum case pre-drill field size estimates of 65 square kilometres. In comparison, the producing MA field covers a reservoir area of 11 square kilometres.

The MJ Field discovery is well positioned to take advantage of the existing KG block infrastructure. Conceptual planning has been initiated to maximize MJ gas and condensate recovery which has a measured compositional ratio of approximately 62 bbls/MMcf.

An initial appraisal program of up to three wells should commence within six to eight months pending government approvals and equipment availability.

Potential Discoveries: Lebah-1, Ajek-1 and Cikar-1 Wells, Various Blocks, Indonesia

The Lebah-1 well, drilled by the operator, ENI, in the North Ganal block, located offshore Kalimantan in the Makassar Strait of Indonesia, penetrated 12 feet of net pay at the top of a 41 foot gross sand Upper Miocene sand interval, a secondary target zone of the well. The joint venture partners have evaluated the potential of this zone and are finalizing plans to drill the Lebah-2 appraisal well in an area of the structure where the zone is believed to be thicker.

The Ajek-1 well, drilled in the Kofiau block, located offshore Papua province in eastern Indonesia, encountered 23 feet of pay over two target Pliocene clastic intervals, with additional thin bedded pay potential. Drilling confirmed the presence of reservoir and hydrocarbon charge, the primary pre-drill concerns in this previously undrilled sub-basin. All sands encountered were hydrocarbon filled with no water leg and C5+ gas composition indicated liquid hydrocarbons. The well has been assessed as a sub-commercial oil and gas discovery. The Company is evaluating the potential of drilling of an appraisal well or one of the other prospects on the block that it believes could contain thicker Pliocene clastic sands.

The Cikar-1 well, drilled in the West Papua IV block, located offshore Papua province in eastern Indonesia, encountered a 700 foot thick section of the targeted New Guinea Limestone primary objective and was still in the porous zone when well conditions forced suspension of drilling operations. The well encountered gas in the drilling of the deeper section and the temporary suspension of the well will allow Niko to return to the well for future deepening and testing. The Company is also evaluating the potential of drilling an appraisal well or one of the other prospects on the block that it believes could also contain thick sections of New Guinea Limestone.

Exploration Opportunities

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

The Company holds interests in contract areas covering 173,922 gross square kilometers of undeveloped land, primarily in Indonesia and Trinidad and Tobago.

Indonesia

The Company has interests in PSCs for 22 offshore Indonesian exploration blocks, covering 119,145 square kilometres. The table below indicates the operator, the location of, the award date, Niko's working interest and the size of the block, as at March 31, 2013.

Block Name	Operator	Offshore Area	Award Date	Working Interest(1)	Area (Square Kilometres)
Lhokseumawe(2)	Zaratex	Aceh	Oct. 2005	30%	4,431
Bone Bay	Niko	Sulawesi SW	Nov. 2008	100%	4,969
South East Ganal	Niko	Makassar Strait	Nov. 2008	100%	3,648
Seram	Niko	Seram North	Nov. 2008	55%	4,991
South Matindok	Niko	Sulawesi NE	Nov. 2008	100%	5,182
West Sageri	Niko	Makassar Strait	Nov. 2008	100%	4,977
Cendrawasih	Niko	Papua NW	May 2009	100%	4,991
Kofiau	Niko	West Papua	May 2009	57.5%	5,000
Kumawa	Niko	Papua SW	May 2009	100%	5,004
East Bula	Niko	Seram NE	Nov. 2009	55%	6,029
Halmahera-Kofiau	Niko	Papua W	Nov. 2009	51%	4,926
North Makassar	Niko	Makassar Strait	Nov. 2009	30%	1,787
West Papua IV	Niko	Papua SW	Nov. 2009	49.9%	6,389
Cendrawasih Bay II	Repsol	Papua NW	May 2010	50%	5,073
Cendrawasih Bay III	Niko	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV	Niko	Papua NW	May 2010	50%	3,904
Sunda Strait I	Niko	Sunda Strait	May 2010	100%	6,960
Obi	Eni	Papua W	Nov. 2011	51%	8,057
North Ganal	Statoil	Makassar Strait	Nov. 2011	31%	2,432
Halmahera II	Niko	Papua W	Dec. 2011	20%	8,215
South East Seram	Niko	Papua SW	Dec. 2011	100%	8,217
Aru	Niko	Papua SW	July 2012	60%	8,054

Notes:

(1) The Company has signed various agreements that, subject to government approval, will change the working interests in several of its blocks in Indonesia.

(2) In April 2013 the government approved the Company's relinquishment of its interest in the Lhokseumawe Block.

All of the Indonesian Blocks are in their initial three year exploration period or have received extensions where the three year period is expiring or has expired, with the exception of the Lhokseumawe Block. The seismic work commitments on the majority of the blocks have been fulfilled. As at March 31, 2013, the Company has remaining working commitments to drill a total of ten wells and the Company's share of the remaining minimum work commitments is $112 million to be spent at various dates through June 2015. The minimum work commitments are based on Niko's share of the estimated cost specified in the PSCs for the exploration period and represent the amounts the host government may claim if the Company does not perform the work commitments. The actual cost of fulfilling work commitments may materially exceed the amount estimated in the PSCs. The Company has applied or has plans to apply for extensions where drilling activity is planned. The Company is required to relinquish a portion of the exploration acreage after the first exploration period, however, it has received extensions in order to fulfill the well commitments on certain blocks.

Trinidad and Tobago

Niko holds interests in ten contract areas, covering 9,862 square kilometres. The table below indicates the operator, the location of, the award date, the Company's working interest and the size of the block, as at March 31, 2013.

Exploration Area	Operator	Location	PSC Date	Working Interest	Area (Square Kilometres
Block 2AB	Niko	Offshore	July 2009	35.75%	1,606
Guayaguayare Area - Shallow Horizon	Niko	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare Area - Deep Horizon	Niko	Onshore/Offshore	July 2009	80%	1,190
Central Range Area - Shallow Horizon	Paraex	Onshore	September 2008	32.5%	734
Central Range Area - Deep Horizon	Paraex	Onshore	September 2008	40%	856
Block 4(b)	Niko	Offshore	April 2011	100%	753
Block NCMA 2	Niko	Offshore	April 2011	56%	1,019
Block NCMA 3	Niko	Offshore	April 2011	80%	2,106
Block 5(c)	BG Group	Offshore	July 2005	25%	241
MG Block	Niko	Offshore	July 2007	70%	223

As at March 31, 2013, Niko had remaining minimum work commitments to drill a total of ten wells on its Trinidad and Tobago Blocks. At that time, the minimum remaining work commitments under the PSCs were $167 million to be spent at various dates through April 2016. The actual cost of fulfilling work commitments may materially exceed the amount estimated in the PSCs.

OTHER PROPERTIES

India

Hazira Field

Niko is the operator of and holds a 33.33 percent interest in the Hazira Field, located about 25 kilometers southwest of the city of Surat and covering an area of 50 square kilometers on and offshore. Niko and GSPC have constructed a 36-inch gas sales pipeline to the local industrial area. The Company has constructed an offshore platform, an LBDP, a gas plant and an oil facility at the Hazira Field. The Company has one significant contract for the sale of natural gas at a price of $4.86/Mcf, expiring April 30, 2016, and the commitment for future physical deliveries under this contract exceeds the expected future production from the Hazira Field. Refer to note 14(c) to the consolidated financial statements for year ended March 31, 2013 for a complete discussion of this contingency.

Surat Block

The Company holds and is the operator of the 24 square kilometer Surat Block located onshore adjacent to the Hazira Field. The natural gas production from the Surat Block commenced in April 2004 and ceased in November 2012 as the cap on cumulative production in the approved field development plan was reached. The Company plans to relinquish the block.

Madagascar

In October 2008, the Company farmed into a PSC for a property located off the west coast of Madagascar covering approximately 16,845 square kilometers. The Company will earn a 75 percent participating interest in the Madagascar block and is the operator of this block. The Company has completed a multi-beam sea bed coring and 3,200 square kilometers of 3D seismic on the block. The Company has work commitments for an exploration well to be drilled prior to September 2015 and its share of the costs of the remaining commitments pursuant to the PSC is $10 million. The actual cost of fulfilling work commitments may exceed the amount estimated in the PSC. The Company is working with various parties on farm-outs to reduce its share of future drilling costs.

Pakistan

The Company holds and operates the four blocks comprising the Pakistan Blocks, located in the Arabian Sea near the city of Karachi and covering an area of 9,921 square kilometers. The Company has applied for relinquishment of all of the Pakistan Blocks.

Canada

The Company has a 45 percent non-operated interest in the Cullen unit in Saskatchewan. It produced 36 bopd gross (16 bopd net) in Fiscal 2013 (Fiscal 2012 - 38 bopd gross (17 bopd net)).

TERMS OF AGREEMENTS GOVERNING EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

General Description

Niko is party to long-term agreements with the governments in each of the respective countries where Niko holds properties. These agreements provide 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 natural gas reserves for the lands under agreement. If Niko is unable to complete the work program, Niko has the ability to surrender its rights prior to the end of the exploration term by making pre-determined payments to the relevant government based on the outstanding work commitments under the contract. Unless specifically provided for in the agreements, each agreement terminates at the end of the exploration period if no commercial discovery is made.

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 natural gas produced from the block. For all properties, Niko 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 the relevant agreement, the host government has the right to terminate the agreement in question and the Company may be liable to make certain payments to the relevant government related to the work commitments. 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 host 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 host 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 the 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.

Specifics by Country

Terms of the Indian PSCs

Under the terms of the PSCs for D6 Block and NEC-25, the GOI is the sole owner of the oil and natural 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. In addition to the terms referred to under "General Description", the PSCs for D6 Block and NEC-25 provide:

(a) A formula for sharing in the profit oil and gas produced from the blocks between the participants and the GOI. The formula is applied on a field-by-field basis. Under the terms of the PSCs for the D6 Block and NEC-25, 90 percent of revenue can be used to recover costs. Under the terms of the PSCs, the GOI is entitled to a 10 percent interest in the profit oil and natural gas produced if the participants have recovered less than 150 percent 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 the D6 Block and NEC-25:

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

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.

(b) A specific work commitment for each block, 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.

(c) Subject to an extension of time approved by the GOI, a requirement to relinquish up to 25 percent 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 percent of the block in the case of the D6 Block and NEC-25. In all cases, the Company can retain the development and discovery areas.

(d) Upon approval of a development plan and designation of a development area by the GOI, the joint venture partners are required to submit a proposed annual work program and budget for development and production operations in respect of each development area. Additionally, the joint venture partners may be required to prepare an estimate of potential production to be achieved through the implementation of the proposed work program and budget for each of the three years subsequent to the year for which the proposed work program and budget relate.

(e) Once commercial production has commenced, and on an annual basis thereafter, the joint venture partners will determine and submit to the management committee for approval, the maximum quantity of petroleum which can be produced from a particular development area in the relevant year. This determination will be based on the estimates of the joint venture partners, as approved by the management committee, and will assume operations are conducted in accordance with good international petroleum industry practices and minimising unit production costs, taking into account the capacity of the producing wells, gathering lines, separators, storage capacity and other production facilities available for use during the relevant year as well as the transportation facilities up to the delivery point.

(f) Payment of royalty to the GOI for offshore areas falling in water depth greater than four hundred metres of 5 percent 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 percent thereafter.

(g) A seven-year tax holiday commencing from the first year of commercial production, however, there is a minimum alternate tax. There is currently uncertainty in India regarding the applicability of this tax holiday to natural gas.

(h) Subject to earlier termination of the PSC, the PSC for a block expires when the license for the block expires.

Certain of Niko's PSCs, including the PSC governing the D6 Block, may be terminated upon certain insolvency events or other defaults. See the risk factors under the heading "Risk Factors" beginning on page 52 relating to the risk of termination of Niko's PSC relating to the D6 Block and see "Legal Proceedings and Regulatory Actions - Proceedings in India".

Terms of the Bangladesh PSC

The Block 9 PSC provides:

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

(b) Subject to an extension of time approved by the GOB, a requirement to relinquish 25 percent of the block at the end of each of the initial exploration period and the first successive exploration period.

(c) The sharing in the profit oil and natural gas among the participants and Petrobangla; under the terms of the Block 9 PSC (i) during the period of cost recovery, the Company shall recover all costs and expenses in respect of all exploration, development, production, operations and related activities to a maximum of 40 percent per calendar year of all available oil and 45 percent per calendar year of all available natural gas, available condensate and available NGL; on the remaining 55 percent, 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 percent of the profit natural gas during cost recovery and 66 percent of the profit natural gas after cost recovery.

(d) Participants may produce annually a total volume of natural gas equal to up to 7.5 percent of the proved 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 percent 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 percent discount, of $70 per metric tonne and a ceiling price, prior to 25 percent discount, of $120 per metric tonne) plus a further one percent 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) 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 percent 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 percent (provided that such final price must be approved by Petrobangla).

(f) 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 bbl/d to 100,000 bbl/d 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). Income taxes are deemed to be included in the GOB profit petroleum.

Terms of the Indonesian PSCs

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

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

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

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

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

(e) The sharing in the profit petroleum among the participants and BPMIGAS; under the terms of the various PSCs, 80 percent of revenues (90 percent in the case of Lhokseumawe) can be used to recover costs; on the revenues not used to recover costs, BPMIGAS's share varies by PSC for each location as follows:

Profit Natural Gas	Profit Crude Oil
28.57 percent to 33.33 percent	37.5 percent to 55.36 percent

(f) Subject to any extension of time approved by BPMIGAS, a requirement to relinquish a certain percentage of the contract area covered by the applicable PSC (i) ranging from 10 percent to 30 percent of the contract area after the first three contract years and an additional 15 percent if the firm commitment has not been completed, (ii) relinquish additional areas in excess of 20 percent 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) Production bonuses and other specified fees.

(i) An obligation to offer a 10 percent participating interest in return for reimbursement of the 10 percent 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.

Terms of the Trinidad and Tobago PSCs

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

(a) 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) 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 percent to 60 percent and from 40 percent to 65 percent, 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 percent recoverable in the first year and 20 percent recoverable in each of the next three years; and operating and administrative costs are recovered in the year they are incurred. Fifty percent of crude oil revenue and 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) A formula for sharing in the profit oil and natural gas produced from the blocks between the Company, its joint venture partners and the GTT on a monthly basis ranging from 30 percent to 63 percent based on production levels and the prices of crude oil and natural gas for Block 2AB, 14 percent to 63 percent for the Guayaguayare Area and 14 percent to 60 percent for the Central Range Area, 50 percent to 75 percent 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 percent to 80 percent based on production levels and the prices of crude oil and natural gas for Block 5(c). Royalty rates in the MG Block are 12.5 percent on natural gas and crude oil.

(d) 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) A requirement 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) Subject to an extension of time approved by the government, a requirement to (i) relinquish 25 to 40 percent of the block at the end of the first phase of the exploration period, (ii) cumulatively relinquish not less than 50 percent 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) 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) 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). For Block 5(c), the GTT share of profit gas includes any tax payable on revenues from the PSC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "**Statement**") is based on reserves evaluations by Ryder Scott and AJM Deloitte, and is effective March 31, 2013. The preparation date of the information regarding reserves in the Statement was May 30, 2013 for Ryder Scott and June 21, 2013 for AJM Deloitte.

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.

Numbers in the tables may not add due to rounding.

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 AJM Deloitte Report for the D6 Block and NEC-25 in India and Block 5(c) in Trinidad and Tobago, and in the Ryder Scott Report for Block 9 in Bangladesh, based on forecast price assumptions presented in accordance with NI 51-101. For Fiscal 2012, Ryder Scott evaluated the Company's interests in the D6 Block in India and Block 9 in Bangladesh. No reserves were assigned to NEC-25 or Block 5(c) during Fiscal 2012.

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 NEC-25), Bangladesh (Block 9) and Trinidad and Tobago (Block 5(c)) and production is 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 Reports on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 are attached hereto as Appendix "A" and Appendix "B" and the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3 is attached hereto as Appendix "C".

Reserves Disclosure — Total India, Bangladesh and Trinidad and Tobago

The following tables detail the Company's estimated aggregate gross and net reserves for both the D6 Block and NEC-25 in India, Block 9 in Bangladesh and Block 5(c) in Trinidad and Tobago, 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
Forecast Prices and Costs As At March 31, 2013

	Light/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						
India	433	398	34,616	31,823	45	42
Bangladesh	-	-	56,526	34,546	171	104
Trinidad and Tobago	-	-	-	-	-	-
Total Proved Developed Producing	433	398	91,142	66,369	216	146
Proved Developed Non-Producing						
India	118	98	15,305	13,113	16	13
Bangladesh	-	-	25,539	13,414	86	45
Trinidad and Tobago	-	-	-	-	-	-
Total Proved Developed Non-Producing	118	98	40,844	26,527	102	58
Proved Undeveloped						
India	514	424	208,525	177,098	62	51
Bangladesh	-	-	17,303	9,825	54	31
Trinidad and Tobago	-	-	196,960	94,957	-	-
Total Proved Undeveloped	514	424	422,787	281,880	116	82
Total Proved						
India	1,065	920	258,446	222,035	123	106
Bangladesh	-	-	99,368	57,785	311	180
Trinidad and Tobago	-	-	196,960	94,957	-	-
Total Proved	1,065	920	554,774	374,777	434	286
Total Probable						
India	587	423	166,664	118,977	64	46
Bangladesh	-	-	48,152	25,171	150	79
Trinidad and Tobago	-	-	37,819	10,963	-	-
Total Probable	587	423	252,635	155,081	214	125
Total Proved Plus Probable						
India	1,652	1,343	425,110	341,012	187	152
Bangladesh	-	-	147,520	82,926	461	259
Trinidad and Tobago	-	-	234,779	105,920	-	-
Total Proved Plus Probable	1,652	1,343	807,409	529,858	648	411

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, the GOB and the GTT.

Summary of Net Present Values of Future Net Revenues
Forecast Prices and Costs as at March 31, 2013(1)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At(2)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category (MM$)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**(US$/boe)(3)**
Proved Developed Producing											
India	130	126	122	117	112	130	126	122	117	112	21.21
Bangladesh	36	33	31	28	26	36	33	31	28	27	5.23
Trinidad and Tobago	-	-	-	-	-	-	-	-	-	-	-
Total Proved Developed Producing	166	159	152	145	138	166	159	152	145	138	13.44
Proved Developed Non-Producing											
India	86	72	60	50	42	79	65	54	45	38	26.03
Bangladesh	16	14	12	11	9	16	14	12	11	9	5.25
Trinidad and Tobago	-	-	-	-	-	-	-	-	-	-	-
Total Proved Developed Non-Producing	102	85	72	61	51	95	79	66	56	47	15.68
Proved Undeveloped											
India	1,287	856	583	405	285	1,003	639	414	271	177	19.45
Bangladesh	11	9	7	5	4	11	9	7	5	4	4.05
Trinidad and Tobago	477	240	121	59	24	477	240	121	59	24	7.66
Total Proved Undeveloped	1,775	1,105	711	469	313	1,491	888	542	335	205	14.98
Total Proved											
India	1,503	1,054	765	572	439	1,212	831	590	433	327	20.11
Bangladesh	63	56	49	44	40	63	56	49	44	40	5.04
Trinidad and Tobago	477	240	121	59	24	477	240	121	59	24	7.66
Total Proved	2,043	1,350	936	675	502	1,752	1,126	761	536	390	14.69
Total Probable											
India	1,336	951	703	538	423	928	659	487	373	294	34.65
Bangladesh	34	25	19	15	11	34	25	19	15	11	4.47
Trinidad and Tobago	84	50	32	22	16	84	50	32	22	16	17.46
Total Probable	1,454	1,026	754	574	450	1,046	734	538	409	320	28.58
Total Proved Plus Probable											
India	2,839	2,006	1,468	1,110	862	2,140	1,490	1,077	805	620	25.17
Bangladesh	97	81	68	59	51	97	81	68	59	51	4.86
Trinidad and Tobago	561	289	153	80	40	561	289	153	80	40	8.68
Total Proved Plus Probable	3,497	2,376	1,690	1,249	952	2,797	1,860	1,299	944	711	18.76

Notes:

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

(2) Income taxes are deemed to be included in the GOB and GTT share of profit petroleum as specified in the PSC for Block 9 and Block 5(c), respectively.

(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, the GOB and the GTT.

The following table provides the elements of future net revenue attributable to the Company's proved reserves and proved plus probable reserves for both the D6 Block and NEC-25 in India, Block 9 in Bangladesh and Block 5(c) in Trinidad and Tobago, estimated using forecast prices and costs and calculated without discount:

Future Net Revenue (Undiscounted)
As At March 31, 2013

Reserves Category (MM$)	Revenue[(1)]	Government Share of Profit Petroleum & Royalties[(2)]	Operating Expenses	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes[(3)]	Future Net Revenue After Income Taxes
Total Proved								
India	3,296	(463)	(481)	(775)	(74)	1,503	(292)	1,212
Bangladesh	261	(110)	(63)	(21)	(4)	63	-	63
Trinidad and Tobago	1,851	(958)	(182)	(234)	-	477	-	477
Total	5,408	(1,531)	(726)	(1,029)	(78)	2,043	(292)	1,752
Total Proved Plus Probable								
India	5,598	(1,103)	(733)	(842)	(81)	2,839	(700)	2,140
Bangladesh	387	(171)	(87)	(28)	(5)	97	-	97
Trinidad and Tobago	2,199	(1,204)	(200)	(234)	-	561	-	561
Total	8,184	(2,479)	(1,020)	(1,103)	(85)	3,497	(700)	2,797

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 including the marketing fee plus the amount of royalties levied by the GOI.

(2) Under the terms of the PSC for the D6 Block and NEC-25, the GOI is entitled to a percentage share of the profit petroleum produced from the blocks, which percentage is based upon the multiple of investment cost recovered by the Company. See "Terms of Agreements Governing Exploration, Development and Production Activities - Specifics by Country - Terms of the Indian PSCs". Under the terms of the PSC for Block 9, the GOB is entitled to a percentage share of the profit petroleum 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 "Terms of Agreements Governing Exploration, Development and Production Activities - Specifics by Country - Terms of the Bangladesh PSC". Under the terms of the PSC for Block 5(c), the GTT is entitled to a percentage share of the profit petroleum produced, which percentage is based upon the production level and prices for crude oil and natural gas. See "Terms of Agreements Governing Exploration, Development and Production Activities - Specifics by Country - Terms of the Trinidad and Tobago PSCs".

(3) Income taxes are deemed to be included in the GOB and GTT share of profit petroleum as specified in the PSC for Block 9 and Block 5(c), respectively.

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 and NEC-25 in India, Block 9 in Bangladesh and Block 5(c) in Trinidad and Tobago, estimated using forecast prices and costs and calculated using a discount rate of 10%:

Future Net Revenue by Production Group
As At March 31, 2013

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% Year) (MM$)	Unit Value[(3)] ($/boe)
Total Proved	Light and medium oil[(1)]	35	14.69
	Natural gas[(2)]	901	
Total Proved Plus Probable	Light and medium oil[(1)]	63	18.76
	Natural gas[(2)]	1,627	

Notes:
(1) Light and medium oil includes solution gas and other by-products. Light and medium oil is only in India.
(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, the GOB and the GTT.

Pricing Assumptions

The following table details the reference prices and inflation rate assumptions as of March 31, 2013 utilized by AJM Deloitte in the AJM Deloitte Report for estimating reserves data disclosed above under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". AJM Deloitte is an independent qualified reserves evaluator and auditor.

Summary of Pricing and Inflation Rate Assumptions
As of March 31, 2013
Forecast Prices and Costs
for India and Trinidad and Tobago

	India Crude Oil	India MA NGL	India Natural Gas	Trinidad and Tobago ($/MMbtu) LNG Market[4]	Trinidad and Tobago ($/Mcf) Local Market		Brent Blended Price[1]	
Fiscal Year	($US/bbl)[2]	($US/bbl)	($US/MMbtu)[2]	($US/MMbtu)	($US/MMBtu)	Inflation Rate (%/Year)[3]	Calendar Year	(US$/bbl)
Forecast								
2014	107.63	88.53	4.21	7.90	5.11	2	2014	112.00
2015	101.36	82.26	10.45	6.51	4.78	2	2015	107.10
2016	94.09	74.99	12.13	5.71	4.61	2	2016	96.75
2017	95.23	76.13	13.67	6.10	4.85	2	2017	98.70
2018	94.74	75.64	13.95	6.49	5.09	2	2018	97.40
Average thereafter	+2%	+2%	+2%	+2%	+2%	2	Average thereafter	+2%

Notes:
(1) Prices are shown in current dollars on a raw received basis.
(2) The natural gas prices for Fiscal 2014 and onwards reflect the anticipated contractual prices upon redetermination by the GOI as estimated by the Company and as included in the Rangarajan Report on the PSC Mechanism in the Indian Petroleum Industry. The pricing scheme proposed uses a blend of Brent, Henry Hub, NBP and Japan Crude Cocktail prices weighted based on forecast gas demand for North America, Europe, Eurasia, Japan and India and is gradually replaced by a price equivalent to imported contract LNG.
(3) Inflation applied to operating and capital expenditures only.
(4) For gas delivered to Atlantic LNG.

The following table details the reference prices and inflation rate assumptions as of March 31, 2013 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, 2013
Forecast Prices and Costs[1]
for Block 9

	Block 9 - NGL	Block 9 - NGL	Block 9 - Natural Gas	Inflation Rate (%/Year)[3]	Brent Blended Price[2]	
Fiscal Year	Proved ($US/bbl)	Proved Plus Probable ($US/bbl)	($US/Mcf)		Calendar Year	(US$/bbl)
Forecast						
2014	103.59	103.59	2.31	2	2013	107.00
2015	99.84	99.84	2.31	2	2014	102.00
2016	99.36	99.36	2.31	2	2015	101.50
2017	98.76	98.74	2.31	2	2016	101.00
2018	97.95	97.95	2.31	2	2017	100.00
Average thereafter	97.88	99.47	2.31	2	Average thereafter	102.13

Notes:

(1) The NGL and natural gas prices shown in the table were provided by Ryder Scott based on discussions with the Company, contractual agreements and sales data provided by the Company 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 2013 were $102.83/bbl for oil and $4.11/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 2013 were $108.32/bbl for NGL and $2.32/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, 2012 and as at March 31, 2013 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type — India[1]
Forecast Prices and Costs

	Light and Medium Oil[2]			Associated and Non-Associated Gas			NGLs		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved plus Probable (Mbbl)
March 31, 2012	68	24	92	131,942	55,010	186,952	755	199	954
Extensions & Improved Recovery	-	-	-	29,906	49,323	79,230	-	-	-
Technical Revisions	1,288	563	1,851	(34,908)	(42,817)	(77,725)	(592)	(135)	(727)
Discoveries	-	-	-	165,115	105,146	270,261	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(291)	-	(291)	(33,608)	-	(33,607)	(40)	-	(40)
March 31, 2013	1,065	587	1,652	258,447	166,662	425,110	123	64	187

Notes:
(1) Amounts do not include Hazira Field or the Surat Block.
(2) Oil volumes reported as at March 31, 2013 reflect FPSO liquid production from the MA Field in the D6 Block and are a combination of volatile oil and field condensate produced, treated and sold as a single fluid at representative oil pricing.

The following table reconciles the changes in the gross reserves estimates for the Company's Bangladesh properties as at March 31, 2012 and as at March 31, 2013 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, 2012	73,960	106,677	180,637
Extensions & Improved Recovery	-	-	-
Technical Revisions	45,461	(58,525)	(13,064)
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(20,052)	-	(20,052)
March 31, 2013	99,369	48,152	147,521

The following table reconciles the changes in the gross reserves estimates for the Company's Trinidad and Tobago properties as at March 31, 2012 and as at March 31, 2013 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type — Trinidad and Tobago Forecast Prices and Costs			
	Associated and Non-Associated Gas		
Factors	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)
March 31, 2012	-	-	-
Extensions & Improved Recovery	-	-	-
Technical Revisions	-	-	-
Discoveries	196,960	37,818	234,778
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	-	-	-
March 31, 2013	196,960	37,818	234,778

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			
2013	424	289,358	105
2012	-	-	-
2011	-	-	-
Prior thereto	-	-	-
PROBABLE UNDEVELOPED			
2013	728	224,975	81
2012	-	-	-
2011	-	-	-
Prior thereto	-	33,156	104

The Company's proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook.

The proved undeveloped and probable undeveloped reserves in the MA and D1-D3 fields in the D6 Block in India are expected to be developed over the next one to two years. The proved undeveloped and probable undeveloped reserves for the R-Series and Satellite Area in the D6 Block are expected to be developed over the next four to five years with re-entry and completion of certain existing wells and the drilling of new wells, all connected with new flow-lines and other facilities into existing D6 Block infrastructure.

The proved undeveloped and probable undeveloped reserves for the J-Series and NEC-25 in India are expected to be developed over the next five years with re-entry and completion of certain existing wells and the drilling of new wells, all connected with new flow-lines and other facilities into a new offshore central processing platform.

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

The proved undeveloped and probable undeveloped reserves in Block 5(c) in Trinidad and Tobago are expected to be developed over the next five to eight years with drilling of new wells, construction of new flow-lines and other facilities, and expansion of an existing platform in an adjacent block.

Additional undeveloped discoveries in the D6 Block and NEC-25 in India and Block 5(c) in Trinidad and Tobago, the undeveloped Chattak and developed Feni properties in Bangladesh, the Indonesian Blocks, the Trinidad and Tobago Blocks (excluding Block 5(c)), and the Madagascar Block 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 2013 and "Risk Factors" herein.

Future Development Costs

The following table details the development costs deducted in the estimation of the Company's future net revenue for the D6 Block and NEC-25 in India, Block 9 in Bangladesh and Block 5(c) in Trinidad and Tobago attributable to proved reserves and proved plus probable reserves (both estimated using undiscounted and forecast prices and costs):

Future Development Costs[1]						
Year (MM$)	**Total Proved Reserves**			**Total Proved Plus Probable Reserves**		
	India	**Bangladesh**	**Trinidad and Tobago**	**India**	**Bangladesh**	**Trinidad and Tobago**
2014	63	15	1	63	15	1
2015	60	7	10	75	14	10
2016	164	1	32	171	1	32
2017	301	1	14	328	1	14
2018	188	1	38	192	1	38
Remainder	74	1	139	94	1	139
Total Undiscounted	850	26	234	923	33	234

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, cash flow from operations, borrowings under the Company's credit facilities and external financing. 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 Wells

The following table summarizes the Company's interests in India, Bangladesh and Trinidad and Tobago, as at March 31, 2013, in oil and gas wells:

Producing and Non-Producing Wells As at March 31, 2013						
	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing[1]						
India - offshore	4.0	0.6	28.0	4.9	32.0	5.5
India - onshore	-	-	22.0	7.3	22.0	7.3
Bangladesh - onshore	-	-	4.0	2.4	4.0	2.4
Trinidad and Tobago	-	-	-	-	-	-
Total Producing	4.0	0.6	54.0	14.6	58.0	15.2
Non-Producing[2][3]						
India - offshore	3.0	0.3	1.0	0.3	4.0	0.6
India - onshore	-	-	12.0	12.0	12.0	12.0
Bangladesh - onshore	-	-	4.0	3.6	4.0	3.6
Trinidad and Tobago	-	-	-	-	-	-
Total Non-Producing	3.0	0.3	17.0	15.9	20.0	16.2

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 (7.1 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, 2013				
	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2014 (Acres)	
Location	Gross	Net	Gross	Net
Bangladesh	533,213	359,201	-	-
India[1][2][3]	4,129,099	412,910	2,153,346[1][2][3]	220,670[1][2][3]
Indonesia[4]	29,127,579	19,049,577	4,218,752[4]	2,733,263[4]
Madagascar	4,160,715	3,120,536	-	-
Pakistan[5]	2,450,460	2,450,460	2,450,460[5]	2,450,460[5]
Trinidad[6]	2,435,862	1,499,084	553,692[6]	199,183[6]
Total	43,836,927	26,891,767	9,376,249	5,603,576

Notes:

(1) The Company has applied to relinquish the Surat Block and the entire 5,928 acres of the Surat Block are included above.
(2) The Company has applied to relinquish 1,045,551 acres (104,481 net acres) of the D6 Block, which are included above.
(3) The Company has applied to relinquish 1,101,867 acres (110,162 acres net acres) of NEC-25, which are included above.
(4) In April 2013, the Company received approval to relinquish its interest in the Lhokseumawe Block and the entire 802,503 acres (240,825 net acres) of the Lhokseumawe Block are included above. 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.
(5) The Company has applied to relinquish all four Pakistan Blocks and the entire 2,450,460 acres of the four Pakistan Blocks are included above.
(6) The Company has applied to relinquish Block 2AB and the entire 396,657 acres (141,805 acres net) of Block 2ab are included above.

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 undiscounted costs for total proved reserves amounts to $78 million ($21 million discounted at 10%). The undiscounted costs for total proved plus probable reserves amounts to $85 million ($17 million discounted at 10%). The abandonment and reclamation costs related to 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 for total proved reserves is $4 million ($3 million discounted at 10% per year). The amount of such costs expected to be incurred for total proved plus probable reserves is $5 million ($3 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 2013, the Company incurred the following costs on its properties:

	Property Acquisition Costs		Exploration Costs	Development Costs	Total Costs[1]
MM$	Proved Properties	Unproved Properties			
Bangladesh	-	-	-	2	2
India	-	-	1	8	9
Indonesia	-	19	145	-	164
Madagascar	-	-	-	-	-
Pakistan	-	-	-	-	-
Trinidad and Tobago	-	-	60	-	60
Brazil	-	-	12	-	12
Total		19	218	10	247

Note:
(1) Does not include any capital inventory.

The following table sets forth the number of exploration and development wells the Company completed during Fiscal 2013:

	Exploratory Wells[(1)]		Development Wells	
	Gross	Net	Gross	Net
Oil Wells				
India	-	-	-	-
Indonesia	-	-	-	-
Trinidad and Tobago	-	-	-	-
Total	-	-	-	-
Gas Wells				
India	-	-	1	0.10
Indonesia	-	-	-	-
Trinidad and Tobago	-	-	-	-
Total	-	-	1	0.10
Service Wells				
India	-	-	-	-
Indonesia	-	-	-	-
Trinidad and Tobago	-	-	-	-
Total	-	-	-	-
Stratigraphic Test Wells				
India	-	-	-	-
Indonesia	-	-	-	-
Trinidad and Tobago	-	-	-	-
Total	-	-	-	-
Dry Holes				
India	-	-	-	-
Indonesia	3	0.90	-	-
Trinidad and Tobago	2	0.72	-	-
Total	5	1.62	-	-

Note:
(1) Includes appraisal wells. Does not include wells that were drilling or under evaluation as at March 31, 2013.

There were no wells drilled in Bangladesh, Pakistan, Madagascar or Canada during Fiscal 2013.

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 - Disclosure of Reserves Data".

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, 2013:

Average Daily Production[1] Working Interest to Niko Year Ended March 31, 2013				
	Quarter Ended			
	June 30, 2012	September 30, 2012	December 31, 2012	March 31, 2013
India[2]				
Oil (bbls/d)	988	1,173	731	754
NGL (bbls/d)	160	116	87	78
Gas (Mcf/d)	120,459	105,474	88,285	69,833
India - Mcfe/d	127,347	113,208	93,193	74,825
Bangladesh				
Oil (bbls/d)	-	-	-	-
NGL (bbls/d)	190	187	160	160
Gas (Mcf/d)	60,260	58,341	50,498	50,610
Bangladesh - Mcfe/d	61,400	59,463	51,458	51,570
Total - Mcfe/d	188,747	172,071	144,651	126,395

Notes:

(1) Canada volumes are excluded from the table.

(2) India volumes include production from the Hazira Field and Surat Block.

Netback History Natural Gas, Oil and NGL Year Ended March 31, 2013				
	Quarter Ended			
	June 30, 2012	September 30, 2012	December 31, 2012	March 31, 2013
India[1]				
Average Price Received (US$/Mcfe)	4.78	5.01	4.79	4.89
Royalties (US$/Mcfe)[1]	(0.25)	(0.25)	(0.24)	(0.25)
Profit Petroleum (US$/Mcfe)[1]	(0.63)	(0.10)	(0.09)	(0.26)
Production Costs (US$/Mcfe)	(0.50)	(0.68)	(0.63)	(0.70)
Netback (US$/Mcfe)	3.40	3.98	3.83	3.68
Bangladesh[1]				
Average Price Received (US$/Mcfe)	2.62	2.61	2.61	2.61
Royalties (US$/Mcfe)[1]	-	-	-	-
Profit Petroleum (US$/Mcfe)[1]	(0.89)	(0.88)	(0.88)	(0.88)
Production Costs (US$/Mcfe)	(0.36)	(0.43)	(0.40)	(0.47)
Netback (US$/Mcfe)	1.57	1.30	1.33	1.26

Note:

(1) Under the terms of the gas sales contracts that are in place with respect to the Company'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 the Company. 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 in Bangladesh for Fiscal 2013, 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)(1)
D6 Block	796	90,910	110	96,346
Hazira Field	116	4,024	-	4,720
Surat Block	-	1,156	-	1,156
Total— India	912	96,090	110	102,222
Block 9	-	54,936	175	55,986
Total— Bangladesh	-	54,936	175	55,986
Total— Company(1)	912	151,026	285	158,208

Note:

(1) The Company's total excludes the production relating to Canada, as such production comprises less than 0.05% of the Company's production for Fiscal 2013.

Production Estimates

The following table provides the Company's estimated volume of production for Fiscal 2014 from its India and Bangladesh properties derived from the AJM Deloitte Report and the Ryder Scott Report, respectively:

Estimated Production **Forecast Prices and Costs** Estimated production for the year ended March 31, 2014				
	Proved Reserves (Gross)	Proved Reserves (Net)(1)	Proved Plus Probable Reserves (Gross)	Proved Plus Probable Reserves (Net)(1)
India, D6 Block				
Natural Gas (MMcf)	17,860	16,789	19,051	17,908
NGL (Mbbl)	20	19	21	20
Light and Medium Crude Oil (Mbbl)	202	190	211	199
India - MMcfe	19,192	18,040	20,443	19,222
Bangladesh, Block 9				
Natural Gas (MMcf)	20,636	13,712	20,636	13,712
NGL (Mbbl)	65	43	65	43
Light and Medium Crude Oil (Mbbl)	-	-	-	-
Bangladesh - MMcfe	21,026	13,970	21,026	13,970
Total - MMcfe	40,218	32,013	41,469	33,192

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.

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 since November 2004. Also Chairman of the Board for in excess of the last 15 years.	Chairman of the Board, President and Chief Executive Officer of Niko.
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 and 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 since 2005. Prior thereto, Vice President, Operations of Niko.
Robert D. McCrank Alberta, Canada	Chief Compliance Officer	Chief Compliance Officer of Niko since 2011 and a Barrister and Solicitor with 35 years of private practice experience.
Glen R. Valk Alberta, Canada	Chief Financial Officer and Vice President Finance[10]	VP Finance and Chief Financial Officer of Niko since 2013. Prior thereto, Corporate Treasurer of Niko since August 2012. Prior thereto, over 25 years of finance experience with exploration and production companies in Canada, Indonesia and the United States, including ConocoPhillips, Gulf Indonesia and Gulf Canada.

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.

(10) Effective January 1, 2013, Murray Hesje retired from his position with the Company as Vice President, Finance and Chief Financial Officer. Mr. Valk succeeded him in those roles. Mr. Hesje will continue with the Company as a special advisor to the Company and to the board of directors.

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 4,624,814 Common Shares constituting approximately 6.59 percent 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 Niko), 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 Niko) 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 assist the board of directors in fulfilling its responsibility of oversight and supervision of, among other things:

- the audit of the Company's financial statements, managing the relationship with the external auditor, reviewing results of external audit activities and meeting with management and the external auditor;
- the preparation and reporting of the Company's annual and interim earnings press release, annual and interim financial statements and the related management discussion and analysis;
- the Company's accounting and financial reporting practices and procedures;
- the adequacy of the Company's internal controls and reporting procedures; and
- financial risk management.

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

Composition of the Audit Committee

The Audit Committee is comprised of Wendell W. Robinson and C. J. (Jim) Cummings. The Company is currently looking into adding a third member to the Audit Committee, however this has not been finalized. 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) since February 2002 and from 1994 to 2002, he was Managing Director, Global Environment Fund. 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 America 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 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 "D" 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 2013 were CAD$819,900 (Fiscal 2012 — CAD$778,500).

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 2013 were CAD$137,600 (Fiscal 2012 — CAD$52,500).

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 2013 were CAD$32,600 (Fiscal 2012 — CAD$39,500).

All Other Fees

There were no other fees billed during Fiscal 2013 or Fiscal 2012 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 quarterly dividends until June 30, 2012. In September 2012, Niko's board of directors decided to suspend the Company's quarterly dividend in connection with the commencement of the Company's significant exploration drilling program in Indonesia. The level of future dividends, if any, will be reviewed periodically by the Company's board of directors.

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 July 8, 2013, the Company had issued and outstanding 70,215,911 Common Shares and no preferred shares. As at July 8, 2013, the Company had outstanding options to purchase 4,866,936 Common Shares.

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 declared 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.

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 the 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.

Senior Credit Facilities

In January 2012, the Company entered into a three-year facility agreement for a $225 million revolving credit facility and a $25 million operating facility for general corporate purposes.

The financial covenants of the credit facilities, calculated at the end of each fiscal quarter, are as follows:

a) Senior Debt to EBITDAX ratio not greater than 3:1;
b) Debt to EBITDAX ratio not greater than 3.75:1;
c) EBITDAX to Interest Expense ratio greater than 3:1; and
d) Debt to Capitalization ratio not greater than 50%.

As at March 31, 2013, as defined in the Credit Agreement:

a) Senior Debt includes (i) borrowing under credit facilities; and (ii) finance lease obligations;
b) Debt includes (i) Senior Debt; and (ii) senior unsecured convertible notes, less (iii) unrestricted cash and cash equivalents;
c) EBITDAX (for the trailing 12 months ending at the end of each fiscal quarter) includes net income less (i) Interest Expense; (ii) income taxes; (iii) depletion and depreciation expense; (iv) exploration and evaluation expenses; and (v) other non-cash items;
d) Interest Expenses includes (i) interest expense; and (ii) standby and other fees in respect of Debt; and
e) Capitalization includes (i) Debt; and (ii) Shareholders Equity (as defined in the Credit Agreement) (adjusted for the impact of conversion to IFRS).

As at March 31, 2013, the Senior Debt to EBITDAX ratio was 0.9:1; the Debt to EBITDAX ratio was 1.0:1; the EBITDAX to Interest Expense ratio was 7.0:1; and the Debt to Capitalization ratio was 14%, well within the specified financial covenants. Based on the Company's financial forecasts for Fiscal 2014 and Fiscal 2015, the Company expects to remain in compliance with the financial covenants of the credit facility throughout Fiscal 2014 and Fiscal 2015.

The maximum available credit under the Credit Agreement is subject to review based on, among other things, updates to the Company's reserves. In September 2012, the syndicate of lenders confirmed a revised borrowing base amount under the facility to an aggregate of $100 million based on the evaluation of the Company's reserves as at March 31, 2012 and based on an assumption that the pricing for gas sales from the D6 Block in India would remain unchanged at US$4.20/MMbtu for the life of the D6 gas fields. As at March 31, 2013, the Company had borrowed $90 million under the credit facilities. Upon closing of the Company's June Offering, the amounts outstanding and the availability under the credit facility were reduced to $80 million. In connection with the completion of the Company's annual independent reserves evaluation as at March 31, 2013, the borrowing base of the facility will be re-determined by the syndicate banks on or before July 31, 2013, using the new pricing mechanism for domestic gas produced in India that was recently approved by the GOI and will result in a significant increase in the prices for the D6 Block natural gas sales contracts that expire March 31, 2014.

Convertible Senior Unsecured Notes

On December 4, 2012, Niko issued CAD$100 million principal amount of Convertible Notes for aggregate gross proceeds of CAD$202 million. The Convertible Notes bear interest at the rate of 7 percent and are due December 31, 2017. Semi-annual interest payments are due on June 30 and December 31 of each year. The Convertible Notes are direct senior obligations of the Company and rank equally with one another and all other existing and future senior unsecured indebtedness of the Company. The Convertible Notes are guaranteed on a senior unsecured basis by the existing guarantors under the Company's Credit Facilities, being Niko Resources (Cayman) Ltd., Niko (NECO) Ltd. and Niko Exploration (Block 9) Ltd. The guarantees of the Convertible Notes are subordinated to all existing and future guarantees provided to holders of the Company's existing and future senior secured indebtedness.

The Convertible Notes may not be redeemed by the Company prior to December 31, 2015. On and after January 1, 2016 and at any time prior to or on December 31, 2017, the Company may redeem some or all of the Convertible

Notes at their principal amount, plus any accrued and unpaid interest to the date of redemption provided the current market price (as defined in the indenture) is not less than CAD$14.69. Noteholders have the right to convert the whole or part of the Convertible Note into Common Shares of Niko at a conversion price of CAD$11.30. The Company may at its option elect to satisfy its obligation to repay the principal amount of the Convertible Notes due at redemption or maturity. Subject to required regulatory approval and provided that there is no event of default under the indenture governing the Convertible Notes, the Company may elect, from time to time, to satisfy its obligation to pay interest on the Convertible Notes (i) in cash, (ii) by delivering Common Shares to Computershare Trust Company of Canada for sale to satisfy the interest obligations in accordance with the indenture, in which case holders of the Convertible Notes will receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares, or (iii) a combination of (i) and (ii).

Unsecured Notes

On June 13, 2013, the Company issued US$63.5 million principal amount of Unsecured Notes for aggregate net proceeds of approximately US$58.5 million, after deducting the initial purchasers' discount and the estimated related expenses payable by the Company. The Unsecured Notes bear interest at the rate of 7 percent per annum, payable monthly, and will be repaid through twelve equal monthly principal payments commencing August 13, 2013. The Company may repay some or all of the Unsecured Notes, plus any accrued and unpaid interest, by issuing Common Shares of the Company, rather than repaying the Unsecured Notes in cash. If the Company elects to make any portion of a payment in Common Shares, the number of Common Shares to be issued will be determined by dividing the amount to be paid in Common Shares by 94.5 percent of the lower of the volume weighted average price of the shares for the 15 day period prior to the payment date and the volume weighted average price of the Common Shares for the five day period prior to the payment date, subject to certain restrictions. To the extent that the applicable price determined under the above formula is less than 85 percent of the volume weighted average price of the Common Shares for the five day period prior to the payment date then, in lieu of delivering Common Shares, the Company will make a cash payment to the holders of the Unsecured Notes. Additional details regarding the terms of the Unsecured Notes are contained in the material change report of the Company dated June 24, 2013, a copy of which is available at www.sedar.com.

MARKET FOR SECURITIES

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 2013	7.39	5.13	12,006,034
February 2013	10.65	6.58	8,483,693
January 2013	11.60	9.32	8,001,057
December 2012	10.70	8.18	10,001,164
November 2012	13.68	8.01	12,647,376
October 2012	18.50	11.73	10,914,068
September 2012	14.64	8.76	11,458,095
August 2012	20.94	13.73	6,453,897
July 2012	17.68	12.09	6,843,714
June 2012	30.43	11.60	12,453,636
May 2012	43.68	27.81	10,625,004
April 2012	42.26	32.50	4,871,701

The Convertible Notes have been listed and posted for trading on the TSX since December 4, 2012 under the trading symbol "NKO.NT". The following table sets out the price range in Canadian dollars for, and trading volume of, the Convertible Notes as reported by the TSX for the periods indicated:

	Trade Price (CAD$)		**Volume Traded**
	High	**Low**	**# of notes(1)**
March 2013	102	94	2,973
February 2013	117.95	98	5,108
January 2013	120	110.5	8,539
December 2012	114	99.99	6,640

Note:

(1) The Convertible Notes were originally issued in denominations of $1,000. Trading on the TSX allows for the trading of fractional interests in notes. The reported volumes on the TSX represent 1/10th of an interest in the Convertible Notes. Volumes have been adjusted from the TSX reported volumes to reflect the original denomination.

SHAREHOLDER RIGHTS PLAN

A shareholder rights plan was first adopted by the Company and confirmed by shareholders on September 15, 1999. This shareholder rights plan was approved and reconfirmed by the Independent Shareholders in 2002, 2005, 2008 and 2011. The continued existence of the shareholder rights plan must be approved and reconfirmed by the Independent Shareholders 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 amended and restated shareholder rights plan agreement dated September 11, 2011 (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 (the "**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. The following are material risks identified by the Company. However, risks that are at this time unknown to the Company or that the Company currently deems immaterial may develop or become material, as the case may be, and may have an adverse effect on the Company's business, financial condition, operating results and prospects.

Risks Relating to Niko's Business and Operations

Alleged Breach of D6 PSC

In May 2012, the GOI sent a letter to Reliance, as operator, and Niko in connection with the dispute regarding the cost recovery of certain capital costs relating to the D6 Block. See "Legal Proceedings and Regulatory Actions - Proceedings in India - D6 Block" and "Terms of Agreements Governing Exploration, Development and Production Activities". Among other things, the letter alleges that the joint venture partners are in breach of the terms of the PSC for having failed to fulfill their obligations under the terms of the PSC for the D6 Block. Specifically, the GOI disputes the joint venture partners' right to recover certain capital costs and directs them to comply with the addendum to the initial development plan to meet the targets with respect to the gas production rates. In the letter, the GOI also reserves its right to take such other and further actions as it deems appropriate for the alleged breaches of the PSC. Under the terms of the PSC, the GOI is entitled to terminate the PSC if the joint venture parties fail to comply with or contravene the provisions of the PSC in a material manner. The joint venture partners' right to recover certain capital costs is currently the subject of arbitration which will be binding on all parties to the arbitration. Should the arbitral tribunal find for the GOI, there is a risk that the arbitral tribunal could determine that the joint venture partners are in default of the terms of the PSC and in this event, the GOI could seek an order of the tribunal to (i) deny the recovery of costs which are the subject of this dispute, (ii) require specific performance of the terms of the addendum to the initial development plan by requiring Reliance to drill the remaining 28 wells contemplated in phase 2 of such plan, (iii) award monetary damages as a consequence of the breach or (iv) terminate the PSC relating to the D6 Block. Any of the foregoing would have a material adverse effect on the Company's financial condition and results of operations. In addition, a termination of the PSC relating to the D6 Block would result in the loss of the Company's right to produce all reserves associated with the block. In such event, Niko would experience a substantial reduction in its cash flow from operations. Even if the arbitral tribunal does not determine that the joint venture partners are in default of the terms of the PSC, the GOI may still seek to exercise other rights available to it.

Dependence on the D6 Block

The occurrence of any event that would prevent or materially reduce the production of natural gas, NGLs or crude oil from the D6 Block, including physical problems with the infrastructure facilities supporting the field or negative actions taken by any government or regulatory authority in India, would have a significant adverse effect on the Company's cash flows and revenue.

In addition, production volumes from the D6 Block are expected to continue to decline due to natural declines of the fields until planned development activities occur.

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 natural 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 could result in a 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 crude oil and natural gas pipelines and processing equipment and government regulation. Crude 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 crude oil and natural gas operations are also subject to compliance with laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. The interpretation of, or 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 impairments and writedowns. 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.

High Risk Activities of Drilling and Producing

Niko's future financial condition and results of operations will depend on the success of its exploration, development and production activities. The Company's crude oil and natural gas exploration, development and production activities are subject to numerous risks, including the risk that drilling will result in dry holes or not result in commercially feasible oil or natural gas production. Furthermore, a significant portion of the Company's acreage is in unproven fields. Niko's decisions to acquire, explore, develop or otherwise exploit prospects or properties will depend, in part, on the evaluation of production data, engineering studies, and geological and geophysical analyses, the results of which are typically inconclusive or subject to varying interpretations. The cost to the Company of drilling, completing, equipping and operating wells is typically uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in crude oil, NGL and natural gas prices;
- surface access restrictions;
- the price and availability of competitors’ supplies of crude oil, NGLs or natural gas in captive market areas;
- crude oil, NGL or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for crude oil, NGLs and natural gas, including the price and availability of alternative fuels.

Cash Flow and Additional Funding Requirements

Based on Niko's forecasted cash and capital requirements over the next several years, the Company expects that its funds from operations, cash on hand, advances under the Credit Agreement and proceeds from financings will not be sufficient to meet all of the Company's working capital requirements, planned capital expenditures and contractual commitments and the Company will have to borrow funds, sell assets or issue equity in order to meet its minimum work commitments and other planned capital expenditures. Niko's ability to raise financing in the future is subject to market or commodity price changes, economic downturns and the Company's future performance. There can be no assurances that any required financing will be available to the Company when needed or even if it is available, that it will be available on terms that are acceptable to the Company. If such financing is not available or is not available on terms that are acceptable, 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 the Company's 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 the Company and its financial position.

From time to time, Niko 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 debt levels of the Company above industry standards. Based on the Company's future exploration and development plans and the results thereof, the Company may require additional financing, which may not be available or, if available, may not be available on acceptable terms.

Costs to Complete Work Programs May Exceed Minimum Work Commitments

The minimum work commitments disclosed herein are based on the Company's share of the estimated cost included in PSCs and represent the amounts the host government may claim if the Company does not perform the work commitments. As of March 31, 2013 the minimum work commitments in Niko's PSCs totalled $322,000. The actual cost of fulfilling work commitments could exceed the amount estimated in the PSCs and such amounts may be material, which could have a significant adverse effect on financial position, cash flows and revenue of the Company. Niko may not have access to the amount of funding required to carry out the actual cost of such work commitments and, in certain circumstances, may be forced to relinquish its interest and pay the minimum work commitment specified in the applicable PSC to the host government.

Termination of PSCs due to Insolvency

Niko's PSCs relating to the D6 Block and NEC-25 contain provisions that permit the host government to give notice of termination of the applicable PSC in the event that, among other things, the Company or its subsidiaries who are parties to the PSC is adjudged bankrupt by a court of competent jurisdiction or enters into a scheme, arrangement or composition with its creditors or takes advantage of any law for the benefit of debtors, provided that the default is not cured within a specified time period or, in the case of the applicable Indian PSCs, the other contracting parties do not satisfy the GOI that they are willing and would be able to carry out the obligations of the defaulting party or have, with the consent of the GOI, acquired the working interest of the defaulting party. This could have a material adverse effect on the rights of creditors in the event of the Company's bankruptcy.

The host government may also provide notice of termination in the event that Niko or its subsidiaries who are parties to the PSC intentionally and knowingly extracted or authorized the extraction of hydrocarbons without the authority of the host government, other than as may be unavoidable as a result of operations conducted in accordance with generally accepted good international petroleum industry practice, or where a contracting party assigns any interest in the PSC without the prior written consent of the host government, or where a contracting party or its parent, as applicable, fail to comply with the provisions of the PSC or its parental guarantee, as applicable, in a material respect or fails to make any monetary payments required by law or the PSC. In each case, the host government will not exercise its rights of termination if the defaulting party cures the default within the applicable cure period or, in the case of the applicable Indian PSCs, the non-defaulting parties to the PSC satisfy the GOI that they are willing and would be able to carry out the obligations of the defaulting party or have, with the consent of the GOI, acquired the working interest of the defaulting party.

The termination of Niko's PSCs in India would have a material adverse effect on the business, financial condition, results of operations and prospects of the Company.

Performance Guarantees

Niko has provided performance security guarantees to the governments of India and Indonesia totalling $14 million as at March 31, 2013. Niko has also provided parent company guarantees on behalf of its subsidiaries that own Niko's interests in PSCs in Trinidad and Tobago, Madagascar and Pakistan that are limited to the governments from which Niko 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 a number of contractors as provided for in various contracts. The recipients of the guarantees have the right to collect on the respective guarantees if Niko, or its subsidiary, as applicable, 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 or its subsidiary, as applicable.

Dependence on Key Customers

The Company sells all of its production in Bangladesh to Petrobangla. Such sales comprised 23 percent of the Company's total revenues for Fiscal 2013, compared to 16 percent for Fiscal 2012. If Niko were to lose Petrobangla as a customer, it could have a material adverse effect on the Company.

Legal Claims in Bangladesh

During Fiscal 2006, NRBL received a letter from Petrobangla demanding compensation related to uncontrolled gas flow problems that occurred in Chattak in January and June of 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 approximately $108 million in compensation (based on an exchange rate of Bangladeshi taka to US dollar of 77.85 to 1.00 as of March 31, 2013). The arbitration process related to the claims 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 Niko will lose the lawsuit in the Bangladesh law courts. Any negative result to Niko and NRBL with respect to the above could have a materially 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 the International Centre for Settlement of Investment Disputes, or ICSID, to resolve the claims in the legal proceedings referenced above 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 Niko and NRBL could have a materially 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 breaches 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.

Licensing and Regulatory Requirements

Niko's current operations are, and future operations will be, subject to licenses, regulations and approvals of governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil and natural gas, taxation and environmental and health and safety matters. The Company cannot guarantee that such licenses applied for will be granted or, if granted, will not be subject to possibly onerous conditions. Any changes to exploration, exploration and production, or production licenses, regulations and approvals, or their availability to the Company may adversely affect the Company's assets, plans, targets and projections. Niko is subject to extensive government laws and regulations governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and natural gas and many other aspects of the oil and natural gas business. Although the Company believes it has good relations with the governments of the countries in which it operates, there can be no assurance that the actions of present or future governments in these countries, or of governments of other countries in which Niko may operate in the future, will not materially adversely affect the business or financial condition of the Company.

Compliance with Terms of CFPOA Court Order

On June 23, 2011, the Company pled guilty to a violation of the CFPOA for providing a car and a trip to Canada and the United States to the Bangladesh State Minister for Energy in 2005. The Company also received a letter from the Fraud Section of the United States Department of Justice indicating that it was not going to bring any charges against Niko. As a result of the guilty plea, the Company paid a CAD$9.5 million fine and was sentenced to a three-year term of court-supervised probation. The order setting the terms of probation (the "**Order**"), imposes a number of requirements including that Niko notify the Crown and the Court of any credible evidence of any corruption or wrongdoing, cooperate fully with Canadian and U.S. authorities, review and modify the Company's anti-corruption policies and internal controls, and that the Company submits a yearly report, drafted by an independent auditor, reviewing Niko's anti-corruption and compliance programs. While the Company believes that it has complied with all the terms of the Order and fully intends to continue to do so, should the Crown or the Court determine that Niko has failed to adhere to the terms of the Order or breached its plea agreement, it could be subject to additional sanctions including, but not limited to, additional fines, further criminal charges or penalties, additional conditions or requirements of probation, or an extension of the term of probation, as well as additional legal expenses and harm to the Company's reputation, any of which could have a material adverse effect on the business, results of operations and financial condition of the Company.

Anti-Corruption Violations

The CFPOA, the *U.S. Foreign Corrupt Practices Act* and similar anti-bribery laws generally prohibit companies from making improper payments to foreign officials for the purpose of obtaining or retaining business. Given the nature of Niko's business and international operations, the Company has extensive regulatory and business interaction with governments and government-owned entities and frequent contact with persons who may be considered foreign officials in parts of the world that have experienced governmental corruption to some degree, and in which strict compliance with anti-bribery laws may conflict with local customs or practice. In addition, as noted previously, the Company pled guilty in 2011 to a violation of the CFPOA statute for conduct that took place in Bangladesh in 2005 and is currently on a three-year term of probation. The Company may also face civil actions in respect of such violation. While the Company has had an anti-corruption compliance program in effect since 2009, and has improved and is in the process of continuing to improve this program as a result of the Order and probationary status, Niko has not conducted a comprehensive review of its historical activities in all jurisdictions in which it operates. The Company cannot guarantee that its employees, officers, directors, agents, or business partners have not in the past or will not in the future engage in conduct undetected by the Company's processes and procedures and for which the Company might be held liable under applicable anti-corruption laws. Violations of these laws, or allegations or investigations of allegations of such violations, could harm Niko's reputation, disrupt its business and result in a material adverse effect on the business, results of operations, and financial condition of the Company.

Capital Markets

As a result of further weakness in the global economy, Niko, along with other oil and natural 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 many financial institutions has diminished and risk premiums have increased, and may continue to do so. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, Niko's ability to fund future capital expenditures is 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 more limited or unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and the Company's 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 significant unanticipated expenses related to development or maintenance of its existing properties or otherwise, the Company will be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for its capital expenditure plans may result in a delay in development or production of the Company's properties, the loss of properties or legal action taken against the Company.

Credit Facilities

The Company is required to comply with covenants under its existing credit facilities, including the Credit Agreement. In the event that the Company does not comply with the covenants under its credit facilities, repayment could be required by the lenders and Niko could lose its ability to access such facilities in the future. Accordingly, failure to comply with the covenants under its credit facilities could have a materially adverse effect on the Company and its financial condition.

Fluctuating Prices

The Company sells its natural gas production under long term natural gas contracts. In respect of natural gas sales from the D6 Block under long term GSPAs that expire on March 31, 2014,, the price received is subject to a floor of $2.50/MMBtu if Brent crude oil is $25/bbl or lower and a cap of $4.20/MMBtu if Brent crude oil is $60/bbl or more. As a result the Company's natural gas prices could become subject to significant variability over the contract period, in the event that Brent crude oil prices were to decline below $60/bbl. In June 2013, the Cabinet Committee of Economic Affairs of the GOI approved a new pricing formula for domestic gas sales in India, based on the recommendations of the Rangarajan Committee. The pricing formula is based on the average of the prices of imported LNG into India and the weighted average of gas prices in North America, Europe and Japan. For the new long term natural gas contracts that will be entered into effective April 1, 2014, the price Niko will receive for natural gas will be linked to global crude oil and natural gas prices, thus resulting in commodity price risk for periods subsequent to March 31, 2014. In this case, the prices that the Company receives for its natural gas, crude oil and NGL production depend on numerous factors beyond the Company's control. These factors include, but are not limited to, the following:

- the domestic and foreign supply of oil, NGLs and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign oil, NGLs and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxation;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil, NGL and natural gas producing regions;
- technological advances affecting energy consumption and energy supply;
- variations between product prices and applicable index prices; and
- worldwide economic conditions.

Subsequent to March 31, 2014, decreases in global crude oil and natural gas prices may result in a reduction of the Company's net revenue for both crude oil and natural gas and may change the economics of producing from some wells, which could result in a reduction in the volume of the Company's reserves. Substantial declines in the prices of crude oil or contract prices for natural gas could also result in delay or cancellation of existing or future drilling, development or exploration 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 the Company's oil and natural gas reserves, causing a reduction in crude oil and natural gas acquisition and development activities.

Significant or extended price declines could also adversely affect the amount of oil and natural gas that Niko can produce economically. A reduction in production could result in a shortfall in expected cash flows and require the Company to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect the Company's ability to replace production and Niko's future rate of growth.

Operating Risks

The Company's 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. 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 elect, because of the high cost of premiums, 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 Company's cash flows and adversely affect its financial condition.

Taxation Risks

The Company has filed its income tax returns in the Indian state of Gujarat for the taxation years 1998 through 2008 under provisions that provide for a tax holiday deduction for production from the Hazira Field and the Surat Block 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 these rulings 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, 2011 and 2012 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 $59 million, pay additional taxes of approximately $36 million and write off approximately $23 million of the income tax receivable as at March 31, 2013. 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 Niko and its financial condition.

For the 2012 taxation year, Niko has filed its tax return in the Indian state of Maharashtra for its indirect subsidiary that owns Niko's interest in the D6 block under provisions that provide for a tax holiday deduction for natural gas, crude oil and condensate production from the D6 Block. There is a risk that this deduction may be denied by the tax authorities.

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 Company's immediate operations 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 Niko will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Environmental Concerns

Crude oil and natural gas exploration is subject to extensive and changing international, national and local environmental and safety laws, regulations, treaties and conventions in force in the jurisdictions in which the Company operates (for example, in relation to the plugging and abandonment of wells, discharge of materials into the environment and otherwise relating to environmental protection). 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. Such legislation or regulations may require additional capital expenditures or operating expenses in order for the Company to maintain compliance with international and/or national regulations. The Company may also become subject to additional laws and regulations if it enters new markets. There may be unforeseen environmental liabilities resulting from the Company's operations 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 in which the Company operates. The Company could also become subject to personal injury or property damage claims relating to the release of or exposure to hazardous materials associated with its operations. In addition, failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of the Company's operations. 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.

Climate Change

Due to concern over the risk of climate change, a number of countries have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These regulatory measures may include, among others, adoption of cap and trade regimes, carbon taxes, increased efficiency standards, and incentives or mandates for renewable energy. Compliance with changes in laws and regulations relating to climate change could increase the Company's costs of operating and could require it to make significant financial expenditures that cannot be predicted with certainty at this time.

Additionally, adverse effects upon the oil and natural gas industry relating to climate change, including growing public concern about the environmental impact of climate change, may also adversely affect demand for the Company's services. For example, increased regulation of greenhouse gases or other concerns relating to climate change may reduce the demand for oil and natural gas in the future or create greater incentives for use of alternative energy sources. Any long-term material adverse effect on the oil and natural gas industry could have a significant financial and operational adverse impact on the Company's business that cannot be predicted with certainty at this time.

Labour Concerns

The Company is required to hire and train local workers to conduct its 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 natural 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, Indonesian rupiah, Malagasy ariary and Pakistani rupee versus the U.S. dollar as they are applied to the working capital of the Company's foreign subsidiaries. The financial instruments, which include short-term investments, accounts receivable, long-term accounts receivable, accounts payable and accrued liabilities, borrowings and the Unsecured Notes, are exposed to fluctuations in foreign exchange rates, which are used in the translation of the financial statements of the Company's Canadian and corporate operations to U.S. dollars. The reported U.S. dollar value of the Company's cash and cash equivalents, accounts receivable, short-term investments, accounts payable, Unsecured Notes and borrowings of the Company's Canadian and corporate operations is exposed to fluctuations in the value of the Canadian dollar versus the U.S. dollar. For Fiscal 2013, the Company had a foreign exchange loss of $3.2 million versus a foreign exchange loss of $14.4 million for Fiscal 2012.

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, it may consider acquiring additional oil and natural gas properties. Although the Company performs reviews of properties prior to any such 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 fully assess 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.

Delivery Commitments

The Company had committed to deliver certain minimum quantities of natural gas to customers of production from the Hazira Field in India, and was unable to deliver the minimum quantities for the period ending December 31, 2007. The Company's partner in the Hazira Field delivered the shortfall in return for: (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 $12 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 it is unable to supply gas from the D6 Block to its partner and the arbitration process has commenced.

The Company is currently unable to supply the full contracted quantity of natural 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 the customer. However, due to a change in the gas allocation policy by the GOI and declining volumes of natural gas production from the D6 Block, the Company is currently unable to fulfill the contract. The Company has notified the customer that the underperformance of the Hazira Field reservoir is a *force majeure* event. The customer does not agree with this position and has served the Company with a notice of arbitration. The Company believes that the outcome is not determinable. See "Legal Proceedings and Regulatory Actions—Proceedings in India—Hazira Field".

Conflicts of Interest

Some of the directors and officers of the Company are engaged and will continue to be engaged in the search for oil and natural gas interests on their own behalf and on behalf of other corporations and situations may arise where such directors and officers will be in direct competition with the Company. From time to time, the Company may jointly participate in exploration and development activities with one or more corporations with which the directors or officers of the Company may be involved. Conflicts of interest could arise among the Company and one or more of its directors or officers and any conflict of interest may be resolved in a manner that does not favour the Company.

Ban or Restriction on Offshore Drilling

Protection of the environment continues to be a high and visible priority of many governments and public interest groups throughout the world. Offshore drilling in certain areas has been opposed by environmental groups and, in some areas, has been legally restricted. The Company's operations would be limited and adversely impacted and its assets could become more expensive to operate if new laws are enacted or other governmental actions are taken that prohibit or restrict offshore drilling or impose additional environmental protection requirements. Moreover, the Company may have no right to compensation from its customers if its costs are increased through such governmental actions, and its operating margins may fall as a result. In addition, significant changes in regulations regarding future international exploration and production activities or governmental or regulatory actions could require costly compliance measures.

Events in recent years, in particular the Deepwater Horizon drilling rig accident in April 2010 and resulting oil spill, have heightened environmental and regulatory concerns about the oil and gas industry.

Risks Relating to Reserves

No Ownership in Oil and Natural Gas Reserves

Pursuant to the laws of India, Bangladesh, Indonesia, Trinidad and Tobago, Madagascar and Pakistan, crude oil and natural gas reserves are considered assets of the applicable government. Therefore, the concessionaire owns only the crude oil and natural gas that it produces under the concession agreements. Oil and gas companies operating in these jurisdictions acquire the exclusive right to explore, develop and produce reserves discovered within certain concession areas pursuant to the applicable agreement awarded by the host government. However, if the host government were to restrict or prevent concessionaires, including Niko, from exploiting these crude oil and natural gas reserves, or interfere in the sale or transfer of the production, Niko's ability to generate income would be materially adversely affected, and any such restriction or interference would have a material adverse effect on the Company's expected results of operations and financial condition.

Availability of Additional Reserves

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

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of reserves and future net revenues to be derived therefrom, including many factors beyond the Company's control. The reserve and future net revenue information set forth herein represents estimates only and may ultimately prove to be inaccurate. Such estimates represent subjective judgments based on available data and the quality of such data. Different reserves engineers may make different estimates of reserves quantities and future net revenues attributable to the production of such quantities. Evaluations of reserves and future net revenues depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Future natural gas prices used in the Ryder Scott Report and the AJM Deloitte Report are based on contractual agreements currently in place and, in respect of the D6 Block for periods after March 31, 2014, future natural gas prices reflect the Company's anticipated contractual prices upon redetermination. Future crude oil and NGL prices reflect Ryder Scott’s and AJM Deloitte's current estimates, which are based on a number of assumptions that are subject to change and are beyond the control of the Company. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data.

Reserve estimates may require revision based on a number of 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. Market price fluctuations of crude oil and natural gas prices may render the recovery of certain reserves uneconomic.

The present value of estimated future net revenue referred to herein should not be construed as the fair market value of estimated oil and natural gas reserves attributable to properties of the Company. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

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 its 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.

Non-Operator of Joint Ventures

The Company's proposed development opportunities are conducted as joint ventures where its not the operator and where it has a limited ability to influence or control future development or operations, safety and environmental standards and amount and timing of capital expenditures following its initial investment decision. The Company's partners that operate these properties may not necessarily share the Company's health, safety and environmental standards or strategic or operational goals, which may result in accidents, regulatory misalignments, project delays or unexpected future costs, all of which may affect the viability of these projects.

Risks Relating to Third Parties

Government Approvals

The Company is dependent on receipt and maintenance of government approvals, 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 its 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 face similar delays or fail to obtain or maintain the necessary approvals, licenses, registration or permits. If any of these occur, the Company or the sub-contractors or other counterparties that perform obligations for it 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.

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 and may delay exploration and development activities. To the extent the Company is not the operator of its oil and natural gas properties, it will be dependent on such operators to comply with the terms of the agreements granting the interests in the Company's 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 or the timing of capital expenditures.

Infrastructure

Infrastructure development in many of the countries in which the Company operates is limited. This may affect the Company's ability to explore and develop its properties and to store and transport its oil and natural gas production. There can be no assurance that lack of infrastructure in one or more of the countries in which the Company 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 ability to operate in such countries and on its financial conditions or operations.

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, its business, prospects, financial condition and results of operation may be materially and adversely affected.

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 does.

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.

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:

(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$27.10 million as at March 31, 2013); 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. 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 explosions caused by 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 the 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 percent 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 Compoany'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 - Risks Relating to Niko's Business and Operations - Legal Claims in 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 $12 million. The Company believes that the agreement with its partner is not effective, as the GOI's gas utilization policy prevents it from supplying the gas to the partner. The Company's partner has served a notice of arbitration, 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 7.35 Bcf until the end of the contract. The Company believes that the outcome of this matter is not determinable at this time. See "Other Properties - India - Hazira Field".

D6 Block

In a May 2012 letter, the GOI alleged that the joint venture partners in the D6 Block are in breach of the PSC for the D6 Block as they failed to drill all of the wells and attain production levels contemplated in the Addendum to the Initial Development Plan for the Dhirubhai 1 and 3 fields. The GOI has further asserted that joint venture costs totalling $1.462 billion (the Company's share totalling $146.2 million) are therefore disallowed for cost recovery. The joint venture partners are of the view that the disallowance of recovery of costs incurred by the joint venture has no basis in the terms of the PSC and that there are strong grounds to challenge the action of the GOI. Reliance has commenced arbitration proceedings against the GOI challenging the allegations and the disallowance of cost recovery. To the extent that any amount of joint venture costs are disallowed, such amount would be treated as profit petroleum in the future, a portion of which would be payable to the GOI under the PSC. Because profit petroleum percentages for the joint venture partners and the GOI change as the joint venture partners recover specified percentages of their investments, the potential impact on the Company's future profit petroleum expense (which represents the GOI's share of profit petroleum) is dependent on the future revenue and expenditures in the block and cannot be precisely determined at this time. Based on the economic inputs used for the proved and proved plus probable reserves in the March 31, 2013 AJM Deloitte Report, the Company has estimated the potential undiscounted before tax impact to be between $23 to $52 million. The arbitral tribunal is in the process of being constituted with Reliance and the GOI having nominated two of the three arbitrators. Pursuant to the terms of the PSC, any action by the GOI to terminate the PSC cannot take place so long as the arbitration proceedings relating to the dispute continue and thereafter may only take place when and if consistent with the arbitral award. The Company expects the arbitration proceedings to commence later this year and the outcome of these proceedings is uncertain. See the risk factors under the heading "Risk Factors" beginning on page 52 relating to the risk of termination of the Company's PSC relating to the D6 Block and see "Assets - Producing Assets - D6 Block, India".

Proceedings in Canada

CFPOA

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 anti-corruption 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 - History - Bangladesh".

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 it, 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 2013 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. AJM Deloitte prepared the AJM Deloitte Report referred to in this Annual Information Form. See "Statement of Reserves Data and Other Oil and Gas Information". Both Ryder Scott and AJM Deloitte have also signed their respective 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 and AJM Deloitte who participated in or who were in a position to directly influence the preparation of the Ryder Scott Report and the AJM Deloitte Report own less than one percent 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 prepared in connection with the most recent annual meeting of shareholders of the Company that involved the election of directors. Additional financial information is also provided in the Company's financial statements and management's discussion and analysis for Fiscal 2013. 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, Devon 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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2013, 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, 2013, 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 May 30, 2013	Bangladesh	N/A	$68,497	N/A	$68,497

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 30th day of May, 2013

Signed *"Larry P. Connor"*
Larry P. Connor, P.Eng.
Managing Senior Vice President

APPENDIX "B"

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2013, 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, 2013, 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
AJM Deloitte Company	Niko Resources Ltd. Reserve estimation and economic evaluation March 31, 2013	India	-	$1,468,261	-	$1,468,261
		Trinidad and Tobago	-	$153,218	-	$153,218

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:

AJM Deloitte Company, Calgary, Alberta, Canada

Execution Date: Dated as of the 21st day of June, 2013

Signed "*Robin G. Bertram*"
Robin G. Bertram, P.Eng. Partner

APPENDIX "C"

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") is 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, 2013, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators is presented in this Annual Information Form of the Company for the year ended March 31, 2013.

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 Form 51-101F1 containing 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: July 8, 2013

APPENDIX "D"

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.