NIKO RESOURCES LTD

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED MARCH 31, 2015

Dated: June 24, 2015

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ABBREVIATIONS AND DEFINITIONS

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

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

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

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

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

Common Terms and Abbreviations

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;

"**ANP**" means Agência Nacional do Petróleo, Gás Natural e Biocombustíveis;

"**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.;

"**BG International**" means BG International Limited;

"**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 3 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;

"CCAA" means Companies' Creditors Arrangement Act (Canada);

"**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;

"**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 2012 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 2012 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 provided 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;

"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, Block 9 in Bangladesh prepared by Deloitte LLP dated June 10, 2015 and effective March 31, 2015;

"D6 Royalty Agreement" means the agreement dated December 23, 2013 between Cortes Royalty Limited, an affiliate of the lenders under the Facilities Agreement and Niko (Neco) Ltd. relating to the D6 Block;

"**Diamond Offshore**" means Diamond Offshore Drilling Inc;

"**Diamond Settlement Agreement**" means the settlement agreement entered into with subsidiaries and affiliates of Diamond Offshore;

"**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 (OverseasXVII) Limited, an indirect wholly-owned subsidiary of Niko, and BPMIGAS effective November 30, 2009;

"Facilities Agreement" means the definitive facilities agreement dated December 23, 2013 among the Company, certain institutional investors and Wilmington Trust (London) Limited, as agent of the lenders and security trustee, providing for senior secured term loan facilities in an initial aggregate amount of $340 million;

"Farm-in Rights Agreement" means the agreement dated December 23, 2013 among Cortes Farmin Limited, an affiliate of the lenders under the Facilities Agreement, Niko Resources (Cyprus) Limited and certain other indirect subsidiaries of the Company pursuant to which Cortes Farmin Limited was granted four exclusive, irrevocable non-assignable rights to purchase farm-in interests in pre-selected Indonesian PSCs held by the Company;

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

"First Amendment to Facilities Agreement" means the first amendment to the original senior secured Facilities Agreement dated December 20, 2013 for an initial aggregate amount of $340 million. The first amendment was dated February 12, 2015;

"**Fiscal 2006**" means the fiscal year of the Company ended March 31, 2006; "**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; **"Fiscal 2015"** means the fiscal year of the Company ending March 31, 2015; and **"Fiscal 2016"** means the fiscal year of the Company ending March 31, 2016;

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

"GCV" means gross calorific value;

"**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**" means 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;

"Guidelines" means India's Domestic Natural Gas Guidelines, 2014;

"**Grand Prix Block**" means the contract areas known as Grand Prix located in west coast of Madagascar, as identified in a PSC entered into by OMV Offshore Morondava GmbH, Niko Resources (Overseas VIII) Limited, and Enermad Corp in October 2007 and amended in August 30, 2013;

"**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;

"ICSID" means International Centre for Settlement of Investment Disputes;

"IFC" means International Finance Corporation;

"**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;

"**Indenture**" means the trust indenture dated December 4, 2012 relating to the creation and issuance of $115 million principal amount of Convertible Notes between the Company and Computershare Trust Company of Canada (the "Trustee");

"**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, Semai V 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;

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

"**Kris Energy**" means KrisEnergy Asia Holdings BV, formerly Tullow Bangladesh Limited;

"**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;

"LBT" means Land and Building Tax;

"**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;

"**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;

"MJ Contingent Resources Report" means an independent resources evaluation report by Deloitte LLP for the MJ Discovery in the D6 Block in India. The evaluation has been prepared in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook, with an effective date of March 31, 2015.

"NCV" means net calorific value;

"**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;

"NRBL" means Niko Resources (Bangladesh) Ltd.;

"**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 Strait Block**" means the contract areas known as North Makassar Strait 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;

"**OMV**" means OMV Offshore Morondava GmbH;

"Ophir" means Ophir Energy Plc;

"**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 PSCs 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;

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

"**2012 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;

"R-Cluster" or **"R-Series"** means gas discovery fields related to the Dhirubhai-34 well in the south portion of the KG-D6 block in India;

"**Range**" means Range Resources Ltd. and its subsidiaries;

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

"Satellite Area" means the four (4) discoveries in the KG-D6 block in India;

"Second Amendment to Facilities Agreement" means the second amendment to the original senior secured Facilities Agreement dated December 23, 2013 for an initial aggregate amount of $340 million and to the first amendment to the facilities agreement dated February 15, 2015. The second amendment was dated June 1, 2015;

"**Secured Loan**" means $60 million seven (7) percent secured term loan agreement entered into on July 17, 2013;

"**Semai V Block**" means the contract area known as Semai V located offshore to the Papua province in Eastern Indonesia, as identified in a PSC entered into by Hess (Indonesia-Semai V) Limited, and BPMIGAS effective November 13, 2008, and acquired by Niko Resources (Overseas XXXII) Limited. on January 24, 2014;

"**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;

"**SHESR**" means Safety, Health, Environment and Social Responsibility;

"**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 Niko Resources (Overseas XXVI) Limited and Niko Resources (Overseas XI) Limited, indirect wholly-owned subsidiaries 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;

"**Term Loan Facilities**" means the senior secured term loan facilities in an initial aggregate amount of $340 million on the terms set forth in the Facilities Agreement;

"**Trinidad Blocks**" means, collectively, Block 2ab, 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;

"**Unsecured Notes**" means $63.5 million principal amount of seven (7) percent senior unsecured notes, issued pursuant to the June 2013 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.

Fiscal Year

The fiscal year for the Company is the twelve (12) month period ending March 31.

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 ninety (90) percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- At least a fifty (50) percent 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 Section 80IB deduction under the Indian Income Tax Act of 1961, 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.
- FPSO hire charges included as operating cost.
- Estimated future abandonment and reclamation costs related to a property have been taken into account by 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 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, government regulation, 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, risks associated with meeting all of the Company's financing obligations and contractual commitments (including work commitments), 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 may include, among others, statements regarding:

- the Company’s ability to achieve certain milestones in the amended terms of the Facilities Agreement related to the Company’s strategic alternatives plan in respect of the potential sale of the Company’s interest in the D6 Block in India;
- the Company’s ability to comply with the terms of the amended Facilities Agreement;
- whether the Company’s restructuring efforts will be sufficient to allow certain of the Company’s exploration subsidiaries to meet existing and future obligations and create necessary financial strength and flexibility needed to fully realize the inherent value of the Company’s assets;
- debt and liquidity levels, and particularly in respect of:
    - the Facilities Agreement and Diamond Settlement Agreement;
    - the proposed sale of non-core assets and farm-out transactions involving exploratory PSC, rescheduling of exploration commitments and settlement of vendor liabilities;
    - deferred obligations under the D6 Royalty Agreements; and
    - the satisfaction of all covenants and conditions under the amended Facilities Agreement;
- a shift in strategic focus of the Company, specifically, the planned limitation of exploration outside of India and Bangladesh, and the planned decrease in commitments and capital obligations with respect to exploration and evaluation assets;
- the interpretation and quantification of the Guidelines issued in October 2014, including the quantum and applicability of gas price premium on the Company’s existing gas fields in D6 and NEC-25 blocks;
- the addition of compressor project in the D6 Block and the sustained production levels resulting therefrom;
- the Company's future development and exploration activities and the timing of these activities, including drilling and workover activities in the D6 Block in India and the corresponding increases in sales volumes from these activities;
- the success in securing farm-outs, swaps, or asset sales in Indonesia, Trinidad and Brazil and the rescheduling of certain of the Company's work commitments;
- the ability to seek joint operating partners;
- sources of funding for the Company’s planned operating, investing, and financing cash outflows;
- the performance characteristics of the Company's oil, NGL and natural gas properties;
- natural gas, crude oil, and condensate production levels, sales volumes and revenue;
- the volume and value of the Company's oil, NGL and natural gas reserves;
- projections of market prices and costs;
- the Company's ability to raise capital and to continually add to reserves through development;
- future funds from operations;

- future royalty rates;
- treatment under governmental regulatory regimes and tax laws;
- work commitments and capital expenditure programs;
- 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 raised 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 operating 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 makes no representation that the actual results achieved during the forecasted period will be the same in whole or in part as those forecasts.

The Company updates forward-looking information related to operations, production and capital spending on a quarterly basis when the change is material and updates reserve estimates on an annual basis. See "Risk Factors" for discussion of uncertainties and risks that may cause actual events to differ from forward-looking information provided here. The information contained here, including the information provided under the heading "Risk Factors", identifies additional factors that could affect the Company's operating results and performance.

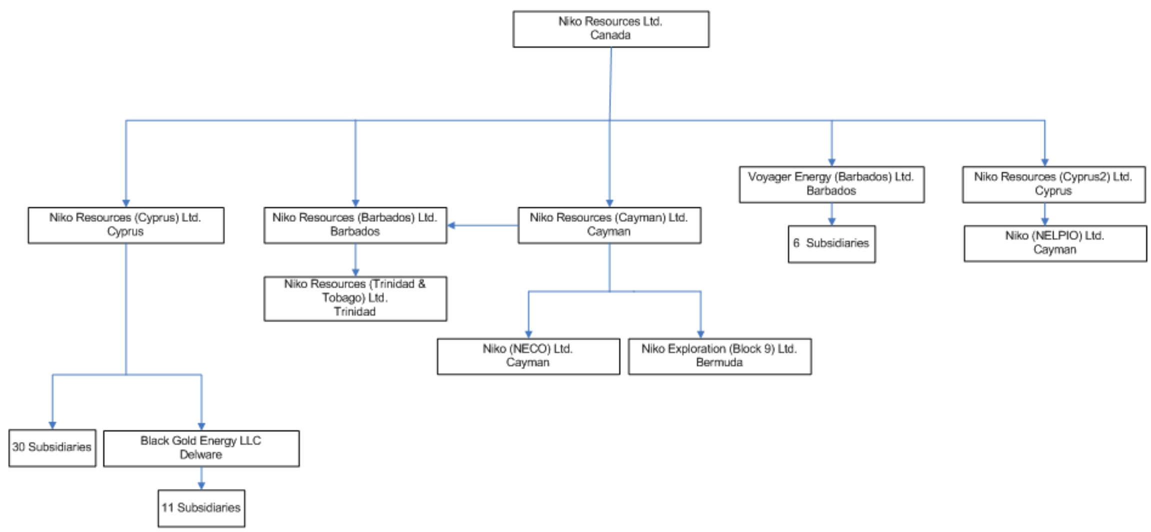
In addition, statements relating to "reserves" and "contingent resources" contained herein are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources described can be economically produced in the future. Future net revenue values are estimated values only and do not represent fair market value. The reserve and resource estimates provided herein are estimates only and there is no assurance that the estimated reserves and other resources will be recovered. Actual reserves and resources may be greater than or less than the estimates provided herein.

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

CORPORATE STRUCTURE

Niko Resources Ltd. 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. The principal and registered office is located at Suite 4600 Devon Tower, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

With certain exceptions, the Company's subsidiaries hold substantially all of its assets. In general, the Company’s interests in each of its PSCs is held by a single subsidiary, with some exceptions: (i) in some cases in Indonesia, two subsidiaries hold interests in the same PSC, and (ii) in Trinidad a single subsidiary holds interests in several PSCs. The following diagram describes the inter-corporate relationships among the Company and its subsidiaries, which are all wholly-owned. Subsidiaries accounting for less than ten (10) percent of the Company's consolidated assets and revenues and in aggregate accounting for less than twenty (20) percent of the Company's consolidated assets and revenues at March 31, 2015 have been excluded from the diagram below.



Notes:
1) Niko (NECO) Ltd. holds interest in the D6 Block in India.
2) Niko (Exploration Block 9) Ltd. holds interest in Block 9 in Bangladesh.
3) Thirty (30) subsidiaries of Niko Resources (Cyprus) Ltd. hold participating interests in twenty seven (27) PSCs (see note 4), of which twenty (20) are located in Indonesia, one (1) in India, two (2) in Brazil, and four (4) in Pakistan.
4) Eleven (11) subsidiaries of Black Gold Energy LLC hold participating interests in eleven (11) PSCs located in Indonesia. Interests in eight (8) of these PSCs are also held by subsidiaries of Niko Resources (Cyprus) Ltd.
5) Six (6) subsidiaries of Voyager Energy (Barbados) Ltd. hold participating interest in six (6) PSCs located in Trinidad and Tobago.

DEVELOPMENT OF THE BUSINESS

General Overview

Niko is a Canadian-based international company focused on value generation in the D6 Block in India, while maintaining optionality to benefit from the exploration potential in its portfolio. As at March 31, 2015, the Company held interests in: (i) producing assets in India and Bangladesh, (ii) development opportunities in India and (iii) exploration acreage in India, Indonesia, Trinidad and Tobago, and Brazil. The Company's Common Shares and Convertible Notes are listed on the TSX under the symbol "NKO" and “NKO.NT” respectively.

As at March 31, 2015, substantially all of Niko's reserves were located in the D6 Block and NEC-25 in India, and Block 9 in Bangladesh and substantially all of Niko's current production is from the D6 Block in India and Block 9 in Bangladesh. Revenue for Fiscal 2015 was comprised of eighty (80) percent natural gas and twenty (20) percent oil and condensate. For further information on individual properties, see "Assets".

Business Strategy

In Fiscal 2014, the Company shifted its strategic focus to developing and appraising the assets in the D6 Block in India, while maintaining optionality of the balance of its exploration portfolio. To provide the financial capacity to implement this strategy, in December 2013, the Company entered into a definitive facilities agreement with certain institutional lenders (the "lenders") providing Term Loan Facilities. At that time, prices for natural gas sales from the D6 Block were expected to approximately double effective April 1, 2014, as per a pricing formula approved by the GOI in June, 2013.

After three deferrals, in October 2014, the GOI approved the new domestic gas pricing policy for India effective November 1, 2014, and issued the Guidelines, which reflected a pricing formula that had been revised from the pricing formula approved in June 2013.

In accordance with the new Guidelines, the price of $5.05 / MMbtu on GCV or $5.61 / MMbtu on NCV for the period of November 1, 2014 to March 31, 2015 increased by approximately thirty three (33) percent from the $4.20 / MMbtu NCV that natural gas sales had been priced at prior to the adoption of the Guidelines, significantly lower than anticipated when the facilities agreement with the lenders had been entered into. The price notified of $4.66 / MMbtu GCV (or $5.18 / MMbtu NCV) by the GOI for the period of April 1, 2015 to September 30, 2015 decreased by approximately eight (8) percent from the price for natural gas sales from November 1, 2014 to March 31, 2015.

Due primarily to the projected impact of the new domestic gas pricing policy for India on the Company's future liquidity and significant uncertainty on the future long-term price outlook in India, in December 2014, the Company engaged Jefferies LLC as its financial advisor to assist the Company in pursuing strategic alternatives including the sale of assets of the Company, a merger or other business combination, the outright sale of the Company, a refinancing of its existing debt with replacement debt, or some combination thereof.

Prior to the amendments outlined below, the Company was subject to the following financial covenants under its Facilities Agreement:

- Maximum ratio of (a) consolidated senior debt (defined as debt incurred under facilities A, B and C of the Term Loan Facilities and finance lease obligations) to (b) the consolidated EBITDAX (as defined in the Facilities Agreement) for the trailing four (4) quarters, commencing with the period ended June 30, 2014.
- Minimum ratio of (a) proved plus probable reserves for the D6 Block to (b) senior debt, commencing with the period ended March 31, 2014 (with the calculation performed annually based on its year-end reserves and financial statements).

The Company's operating results for the trailing four quarters ended December 31, 2014 were not sufficient to satisfy the senior debt to EBITDAX financial covenant and under the original agreement a breach of this covenant would have resulted in the right for the lenders to accelerate payment of the outstanding principal amount of the Term Loan Facilities of $308 million. Due to cross default provisions of the note indenture for the Company's seven (7) percent senior unsecured convertible notes due December 31, 2017 ("Convertible Notes"), an event of default under the Facilities Agreement that was not cured within forty five (45) days would have permitted the holders of the Convertible Notes to accelerate payment of the outstanding principal amount of the Convertible Notes.

In February 2015, the Company and its lenders agreed to amend the terms of the facilities agreement in order to ensure that an event of default did not occur. It was believed that the amendment would provide the Company with sufficient time to pursue the potential sale of the Company's interest in the D6 Block in India or the sale of the Company. As the process for the sale of the Company's interest in the D6 Block or the Company did not achieve certain milestones agreed to with the lenders in the first amendment, in May 2014, the Company and its lenders entered into two agreements which, subject to certain conditions, resulted in extensions of milestones to complete the sales process and further extended the waiver of certain financial covenants and undertakings set out in the facilities agreement until September 15, 2015**.**

As per the amendments to the Facilities Agreement, the Company is restricted to specified amounts of capital expenditures for non-core assets and general and administrative expenditures during calendar 2015, and must maintain specified minimum total cash balances. In addition, the Company is restricted from making any interest or other payments under the Convertible Notes, or under the terms of the agreement entered into with Diamond Offshore until September 30, 2015.

Since it now appears unlikely that the Company will be able to achieve the remaining milestones in the amended facilities agreement and that the Company will default under key unsecured obligations, the Company is pursuing an alternative strategic plan with the assistance of its advisors to enhance value over a longer period of time. The Company has been in discussions with its lenders about the structure of this plan and plans to have further discussions with other key stakeholders, including the holders of the Convertible Notes and the parties to the Diamond Settlement Agreement.

History

Origins of the Company

Founded in 1987, Niko's first six (6) 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, and the Company expanded its portfolio into Bangladesh, Indonesia, Trinidad and Tobago, Pakistan, Madagascar and Brazil.

Three Year History of the Company

The following is a description of events and conditions, on a country by country basis, that have influenced the general development of the Company over the past three (3) fiscal years.

India

Fiscal 2013

- In May 2012, the Company relinquished its interest in the D4 Block, an offshore exploration area northeast of the D6 Block, based on the geological assessment related to the size and risk of the trapping mechanism and the 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 independent reserve engineers 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, with approval occurring in August 2013.
- In March 2013, the integrated block development plan for NEC-25 was submitted to the GOI for approval.

Fiscal 2014

- 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. In January 2014, drilling of the successful MJ-A1 appraisal well in the D6 Block was completed. Drilling of the MJ-A2 appraisal well commenced in March 2014 and concluded in June 2014. Refer to "Assets – D6 Block – MJ Discovery" for discussion on the results of the discovery and appraisal wells.
- In December 2014, the workover campaign in the Dhirubhai 1 and 3 fields commenced. The initial two workover operations, one of which occurred in the first quarter of Fiscal 2015, did not succeed due to mechanical well bore difficulties.
- In January 2014, production commenced from the MA-8H development well drilled in the MA field. Drilling of the MA-6H side track commenced in the fourth quarter of Fiscal 2014.

Fiscal 2015

- In October 2014, the Cabinet Committee of Economic Affairs of the GOI approved the new domestic gas pricing policy for India and the GOI issued the Guidelines. The initial price for the period of November 1, 2014 to March 31, 2015 is $5.05 / MMbtu based on the GCV of the sales gas. This price equates to approximately $5.61 / MMbtu based on NCV of the sales gas. As a result, the price for natural gas sales from the D6 Block in India increased by thirty-three (33) percent, effective November 1, 2014.
- In March 2015, the GOI issued a notification that the price for the period of April 1, 2015 to September 30, 2015 shall be $4.66 / MMbtu based on the GCV of the sales gas (which equates to approximately $5.18 / MMbtu based on the NCV of the sales gas), representing a decrease of approximately eight (8) percent from the price for natural gas sales from November 1, 2014 to March 31, 2015.
- In March 2015, the High Court of Gujarat in India issued a favourable judgment on the retrospective application of the definition of undertakings and whether or not mineral oil includes natural gas for the purposes of the income tax holiday claims for the Company's fields in India. The judgment states that the GOI's retrospective application of the definition of undertakings as "all blocks licensed under a single contract shall be treated as a single undertaking" is unconstitutional

and has been struck down. As such, the Company's position that an undertaking can be defined as a well or cluster of wells has been upheld for the purposes of the tax holiday provisions in the Income Tax Act in India. The judgment also states that the term "mineral oil" for the purposes of the tax holiday provisions in the Income Tax Act in India takes within its purview both petroleum products and natural gas. The judgement of the High Court can be challenged before the Supreme Court of India within ninety (90) days from the date of the order of the High Court. Refer to "Risk Factors – Taxation".

- The price for oil and condensate sales for Fiscal 2015 decreased by nearly twenty (20) percent compared to Fiscal 2014 as a result of the decline in world oil prices.
- The MA-6H sidetrack well was brought on-stream in April 2014, and the MA-5H sidetrack well was brought on-stream in March 2015.
- Successful commissioning of three compressors for the Onshore Terminal Booster Compressor project occurred in the fourth quarter of Fiscal 2015, providing operational flexibility to address the decline in reservoir pressure. A program to re-activate certain shut-in wells in the D1 D3 fields began in the first quarter of Fiscal 2016.
- The appraisal of the MJ Discovery announced in Fiscal 2014 continued during Fiscal 2015 with the drilling of the second and third appraisal wells and the completion of phase 1 of a conceptual engineering study for potential development of the field.
- The Company received an independent resources evaluation report for the MJ discovery in the D6 Block effective March 31, 2015 from Deloitte LLP. Deloitte LLP evaluated the contingent resources for the MJ discovery in the D6 Block based on available information including the drilling, testing and coring results of the MJ-1 discovery well and the MJ-A1, MJ-A2 and MJ-A3 appraisal wells. Deloitte's best case estimate of gross unrisked contingent resources of 1.4 trillion cubic feet of equivalent (Niko's share 140 Bcfe) relates to the Central (North), Northern and Central (South) fault blocks that were drilled by the MJ-1, MJ-A1, and MJ-A3 wells, based on an estimated areal extent of approximately twenty four (24) square kilometers, approximately twice the areal extent of the analogous MA field that is currently producing.

Bangladesh

Fiscal 2014

- In June 2014, the Anti-Corruption Compliance Assessment Report issued by an independent audit firm was delivered as required in connection with the CFPOA proceedings. The delivery of this report satisfied the Company's obligations in respect of this proceeding. Refer to "Legal Proceedings and Regulatory Actions - Proceedings in Canada - CFPOA" and "Risk Factors".
- In Fiscal 2014, workovers were completed on two (2) wells in the Bangora field, resulting in sustained production levels.

Fiscal 2015

- Installation of plant compression facilities was completed in the second quarter of Fiscal 2015.

Indonesia

Fiscal 2013

- During the year, three (3) wells drilled in the Lhokseumawe block were not successful and the Company relinquished its interest in the block.
- During the year, three (3) potential discoveries were made with wells drilled in three (3) of the Indonesia Blocks: Lebah-1 in the North Ganal Block, Ajek-1 in the Kofiau Block, and the Cikar-1 well in the West Papua IV block.

Fiscal 2014

- During the first and second quarters of the year, three (3) wells drilled were not successful: one (1) in each of the North Makassar, Cendrawasih and the Kofiau Blocks.
- In September 2013, the Company suspended all drilling activities in the Indonesian Blocks.
- In December 2013, as part of its financial restructuring, the Company entered into an agreement with Diamond Offshore relating to the termination of the Ocean Monarch rig agreement including settlement of the Company's payment obligations and other commitments under drilling contracts for the semisubmersible drilling rigs Ocean Lexington and

Ocean Monarch. The settlement agreement includes a mutual release of claims in respect of Niko's payment obligations to be released upon payment by the Company of $80 million to Diamond Offshore. An initial payment of $25 million was made to Diamond Offshore using proceeds from the initial advance of the Term Loan.

- In January 2014, the GRI approved the transfer of one-hundred (100) percent interest in the Semai V Block to the Company in connection with a definitive agreement signed in August 2013, and the Company received certain consideration in exchange for assuming the interest in the PSC (including a future drilling commitment).

Fiscal 2015

- In October 2014, the Company executed a definitive agreement with a subsidiary of Ophir Energy plc ("Ophir") relating to the sale of the Company's interests in seven (7) Indonesian PSCs for cash consideration of $31 million, with further payments contingent on future exploration success. Upon closing of the transactions, a specified portion of the proceeds would be used to reduce the Company's outstanding contract settlement obligation to Diamond Offshore, with the remainder subject to conditions outlined in the Company's Facilities Agreement. Refer to "History - Recent Developments" for description of subsequent closing of the sale.

Trinidad and Tobago

Fiscal 2014

- In May 2013, the Company and its partner relinquished their respective interests in Block 2AB after the drilling of three (3) unsuccessful offshore wells over the prior two (2) years.
- In September 2013, the Company and its partner relinquished their respective interests in the Central Range Area after the drilling of two (2) unsuccessful wells over the prior two (2) years.
- In the third quarter of Fiscal 2014, the Company transitioned into a financial and organizational restructuring phase whereby management actively engaged in vendor settlement efforts and negotiations with potential joint operating partners to sell or farm out the Company's existing working interests in various blocks.
- In December 2013, the Company executed a farm-out agreement with Range for fifty (50) percent of the Company's interests in the Guayaguayare Area in Trinidad, resulting in a reduction of approximately $16 million of the Company's remaining work commitment in the blocks, subject to government approval. Refer "History - Recent Developments".
- In March 2014, the Company entered into a sale and purchase agreement with BG International for the sale of its Block 5(c) assets in Trinidad.

Fiscal 2015

- In June 2014, the Company closed the sale of its Block 5(c) assets in Trinidad & Tobago for gross proceeds of $62 million. Proceeds from the sale were used to repay approximately $15 million of contract settlement obligations to Diamond Offshore, and $20 million of principal outstanding under Facility E of the Term Loan (including accrued and unpaid interest).

Madagascar

Fiscal 2014

- In August 2013, the Company entered into a farm out agreement with OMV, whereby OMV would earn a forty (40) percent working interest in the Grand Prix Block. The assignment was approved by the Government of Madagascar in September 2013.

Fiscal 2015

- In July 2014, the Company transferred its remaining thirty-five (35) percent interest in the Grand Prix Block in Madagascar to an existing partner in exchange for potential future payments to the Company that are contingent on certain future events in the block.

Brazil

Fiscal 2014

- In September 2013, the Company acquired thirty (30) percent interests in two (2) contract areas in Brazil, covering 985 square kilometers. Both the blocks are in the first exploration period of five (5) years. The Company's share of the minimum work commitments for the acquisition and processing of seismic for the two (2) blocks is $3 million to be spent by September 2018.

Fiscal 2015

- In February 2015, the Company sold its interest in a data acquisition entity in Brazil and reduced its outstanding liabilities.

Corporate - Liquidity and Financing Activities

Fiscal 2013

- In December 2012, the Company repaid its CAD$310 million principal amount of convertible debentures due December 30, 2012 at par plus accrued interest, using the net proceeds of CAD$273 million from the 2012 Public Offering, the Concurrent Offering and cash on hand and advances under the Company's revolving syndicated then credit facilities. The Convertible Notes issued in December 2012 totalling CAD$115 million mature on December 31, 2017.

Fiscal 2014

- In June 2013, the Company completed a private placement of $63.5 million principal amount of Unsecured Notes to a group of institutional investors. The Unsecured Notes bear interest at seven (7) percent per annum and mature on July 13, 2014. The net proceeds of the June 2013 Offering were approximately $58.5 million, after deducting the initial purchasers' discount and the estimated related expenses payable by Niko. The net proceeds were used for general corporate purposes. The terms of the Unsecured Notes were amended in December 2014 in connection with the Term Loan. Refer to "Description of Capital Structure – Unsecured Notes".
- In July 2013, the Company entered into an agreement for a $60 million Secured Loan funded by a group of institutional investors. The Secured Loan bore interest at seven (7) percent per annum, payable quarterly, and was to mature on July 17, 2015 with no scheduled amortization. The net proceeds of $51.5 million were used to fund expenditures related to the Company's PSCs, including work capital commitments. The Secured Loan was secured by pledges of the shares of the Company's subsidiaries that own the Company's interests in the NEC-25 Block in India and two (2) blocks in Indonesia and was guaranteed on an unsecured basis by the Company's subsidiaries that directly or indirectly own the Company's interests in the D6 Block in India. The Secured Loan was fully repaid with the Term Loan in December 2013. In connection with the Secured Loan agreement, the Company also signed exploration option agreements granting farm-in options to the option holder to (i) acquire a five (5) percent working interest in each of two (2) blocks in Indonesia, by paying its proportionate share of previously incurred costs within a specified period after the drilling of the first exploration well in the block, or (ii) receive a cash payment of approximately $10 million if a commercial discovery is made with the first exploration well drilled in the applicable block and the optionee elects not to exercise its farm-in option in the applicable block. The optionee did not exercise its farm-in option for one (1) of the blocks after the drilling of the first exploration well in this block and the exploration option agreement for this block has been terminated. Pursuant to the exploration option agreement still in effect, if a well is not spud in another applicable block in Indonesia prior to July 2016, the Company is obligated to pay approximately $5 million to the option holder.
- In December 2013, the Company entered into the Facilities Agreement with certain institutional investors providing for the Term Loan in an aggregate principal amount of $340 million. As a condition of the Facilities Agreement, a subsidiary of the Company entered into an agreement which provides for monthly payment equal to six (6) percent of the Company's share of gross revenues received from the D6 Block, commencing April 1, 2015 for a term of seven (7) years. As a further condition to the Facilities Agreement, certain direct and indirect subsidiaries of the Company entered into the Farm-in Rights Agreement. The Farm-in Rights Agreement provides the holder with an option to purchase a five (5) percent participating interest in pre-selected Indonesian PSCs (subject to certain restrictions) in exchange for historical costs, expenses and liabilities in relation to the selected PSC in equal proportion to the participating interest thereby acquired.

The option expires on the earlier of the date on which the eighth well on the pre-selected PSCs is spudded and December 20, 2020. Refer to "Description of Capital Structure" for details of the Facilities Agreement.

- In December 2013 contemporaneously with the execution of the Facilities Agreement, the Company raised approximately $30 million in net proceeds for the sale of subscription receipts which were subsequently exchanged for Common Shares. Proceeds of the sale of subscription receipts were used to repay a portion of the Unsecured Notes.

Fiscal 2015

- In June 2014, the Company repaid $20 million of principal outstanding under Facility E of the Term Loan (including accrued and unpaid interest) using proceeds from the sale of its interest in the Block 5(c) asset in Trinidad.
- In July 2014, the Company received the final notice of conversion in accordance with the terms of the Unsecured Notes, reducing the outstanding principal and interest to zero on the Unsecured Notes.
- In December 2014, the Company engaged Jefferies LLC as its financial advisor to assist the Company in pursuing strategic alternatives including the sale of assets of the Company, a merger or other business combination, the outright sale of the Company, a refinancing of its existing debt with replacement debt, or some combination thereof.
- In February 2015, the Company reached an agreement with the institutional lenders of its Facilities Agreement to amend the terms thereof under the First Amendment to the Facilities Agreement. Refer to "Description of Capital Structure – Facilities Agreement" for amended terms. As a result of the amended terms of the Facilities Agreement, the Company made principal prepayments of $20 million on Facility A. Refer to "History – Recent Developments".

<u>Corporate – Personnel Updates</u>

Fiscal 2013

- In January 2013, Murray E. Hesje retired from the position of Chief Financial Officer and Glen R. Valk was appointed as Chief Financial Officer. Mr. Hesje became an advisor to management and the Board of Directors.

Fiscal 2014

- In July 2013, the Board of Directors appointed Norman M.K. Louie as a director of the Company.
- In August 2013, Frederic F. (Jake) Brace joined the Company as a senior advisor.
- In September 2013, Murray E. Hesje and Charles S. Leykum were elected to the Board of Directors of the Company at the annual meeting of shareholders.
- On December 31, 2013, Edward S. Sampson, retired from the positions of President, Chief Executive Officer and Chairman of the Board.
- Effective January 1, 2014, the Board of Directors appointed Frederic F. (Jake) Brace as President of the Company.
- In February 2014, the Board of Directors appointed Wendell R. Robinson as Chairman of the Board of the Company.

Fiscal 2015

- In April 2014, the Board of Directors appointed Tim G. Henry as Vice President, General Counsel and Corporate Secretary.
- In April 2014, the Board of Directors appointed Stewart Gossen to the Board of Directors. Mr. Gossen was appointed as a member of the Audit Committee and Corporate Governance Committee.
- In May 2014, the Board of Directors appointed Harrison A. Bubrosky to the Board of Directors. Mr. Bubrosky was appointed as a member of the Audit Committee and Compensation Committee in June 2014.
- In August 2014, Harrison A. Bubrosky resigned as director of the Board.
- In August 2014, the Board of Directors appointed Kevin J. Clarke and Steven K. Gendal to the Board of Directors.
- In September 2014, the shareholders of the Company ratified and confirmed the adoption by the Board of Directors of the amended and restated By-Law No. 1 and the advance notice by-law of the Company.
- In September 2014, the shareholders elected E. Alan Knowles, Vivek Raj and Joshua A. Sigmon, Mr. Clarke. Mr. Gendal, C.J. (Jim) Cummings, Stewart Gossen and Conrad P. Kathol to the Board of Directors.
- In September 2014, Norman Louie, Charles Leykum, Murray Hesje and Wendell R. Robinson no longer held positions as directors of the Board.
- In September 2014, C.J. (Jim) Cummings, Stewart Gossen and Conrad P. Kathol resigned as directors of the Board.
- In September 2014, Tim Henry resigned as Vice President, General Counsel and Corporate Secretary.

- In October 2014, the Board of Directors appointed Kevin J. Clarke as Chairman of the Board and interim Chief Executive Officer.
- In December 2014, Frederic (Jake) Brace left his position as President of the Company.

Recent Developments

A number of recent developments have occurred subsequent to March 31, 2015 up to the date of this Annual Information Form. Material matters are described as follows:

- In April 2015, the Company closed on transactions for the sale of certain of its subsidiaries holding interests in four Indonesian PSCs (West Papua IV, Kofiau, Halmahera-Kofiau, and Aru) as the first phase of transactions under a definitive agreement executed in October 2014 with a subsidiary of Ophir. The cash consideration of $16 million received reflects $9 million of combined net working capital obligations of the subsidiaries acquired by Ophir. Further payments under these transactions are contingent on future exploration success. Approximately $4 million of the cash consideration was used to reduce the amount outstanding under the Diamond Settlement Agreement and $9 million was used to pay outstanding tax liabilities in Indonesia and costs associated with the transactions. Closings of the transactions for the sale of the Company's interests in two (2) additional Indonesian PSCs (North Ganal and North Makassar Strait) are subject to the satisfaction or waiver of the remaining conditions precedent. Niko is contesting the LBT assessments related to certain Indonesian PSCs and has indemnified Ophir for any potential LBT obligations related to the subsidiary that owns an interest in the Aru PSC and at closing, would do so for the subsidiary that owns its interest in the North Ganal PSC. As a result of the sales in April 2015, the Company recognized reversals of impairments of $23 million as at March 31, 2015.
- In May 2015, the Company executed agreements to sell its entire interests in the Guayaguayare Shallow and Deep PSCs to Range, effectively amending the terms of previously executed farm-out agreements. Under the sale agreements, the Company will sell its interests in the PSCs in exchange for the assumption of existing liabilities and commitments under the PSCs and for potential future payments that are contingent on certain future events in the PSCs. Closing of the sale transactions are subject to certain conditions, including the approval of the GOTT.
- In the first quarter of Fiscal 2016, the Company agreed with its lenders of its Facilities Agreement to further amend the terms of the Facilities Agreement, including the deferral to September 2015 of the interest payment of approximately $10 million due in June 2015, a reduction in the required minimum balance of the reserve account for anticipated expenditures in the D6 Block from $30 million to $20 million, an extension of the waiver of certain financial covenants and undertakings until September 15, 2015, and restrictions on any interest or other payments under the Convertible Notes or under the Diamond Settlement Agreement until September 30, 2015. In conjunction, the Company made principal prepayments of $30 million on the Term Loan Facilities, reducing the outstanding balance to $250 million. Refer to "Description of Capital Structure – Facilities Agreement".

Social Responsibility and Environmental Impact on the Company's Business

The Company currently abides by the Safety, Health, Environment and Social Responsibility ("SHESR") policy which was implemented on August 13, 2007. SHESR are intended to ensure the Company's activities do not compromise the wellbeing of the Company's employees, contractors, communities or the environment in which the Company operates in.

The Company is required to comply with the Environmental and Social Action Plan required under the terms of the Facilities Agreement. The plan includes the development of a wide range of social and environmental policies and procedures according to fixed timelines, and is subject to International Finance Corporation's approval.

According to IFC's Procedure for Environmental and Social Review of Projects ("IFC Procedure") a limited number of specific environmental and social impacts may result which can be avoided or mitigated by adhering to generally recognized performance standards, guidelines or design criteria. The following potential environmental, health and safety and social impacts under the IFC procedure is under progress:

- Corporate environmental management system ("EMS");
- Environmental and social performance of existing holdings of Niko's existing operations and compliance of future operations;
- Coastal zone management;
- Air emissions;

- Water supply and disposal;
- Liquid and solid waste disposal;
- Noise from drilling and operations;
- Occupational health and safety issues including fire protection, emergency response, and control of employees exposure to noise and dust;
- Land acquisition; and
- Community consultation and disclosure.

In response, the Company has plans to address the above impacts to ensure that the IFC Procedure will, upon implementation, comply with applicable host country laws and regulations including IFC requirements. The Company is currently revising the existing SHESR to integrate various impacts and, the Company has obtained environmental licences for the India blocks.

ASSETS

India

D6 Block, India

The Company entered into the PSC for the D6 Block in India in 2000 and has a ten (10) percent working interest, with Reliance, the operator, holding a sixty (60) percent interest and BP holding the remaining thirty (30) percent interest. The original block of 7,645 square kilometers is located off the coastline of Andhra Pradesh. The remaining petroleum mining lease acreage comprises 1,446 square kilometers after relinquishment.

Successful exploration programs led to twenty (20) discoveries in the block, including the discoveries of the Dhirubhai 1 and 3 natural gas fields in 2002 and the MA crude oil and natural gas field in 2006.

Dhirubhai 1 and 3 Fields

Field development of the Dhirubhai 1 and 3 fields included the drilling and tie-in of eighteen (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. 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 (4) additional wells have been drilled in the post-production phase of drilling. Based on the information obtained from three (3) wells drilled within the main channel fairway, the Company has determined that it is not economic to tie-in any of these three (3) 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. Eight (8) of the original eighteen (18) wells had been shut-in. Successful commissioning of three compressors for the Onshore Terminal Booster Compressor project occurred in the fourth quarter of Fiscal 2015, providing operational flexibility to address the decline in reservoir pressure. A program to re-activate certain shut-in wells in the D1 D3 fields began in the first quarter of Fiscal 2016.

MA Field

Production from the crude oil discovery in the MA field commenced in September 2008 and commercial production commenced in May 2009. With the addition of the MA-8 development well drilled in Fiscal 2014, seven (7) 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 (4) of these wells are currently on production, including the MA-6H sidetrack well that was brought on-stream in April 2014 and the MA-5H side track that was brought on-stream in March 2015.

R-Cluster Gas Fields Development Project

The field development plan for the R-Cluster gas discovery was approved by the GOI in August 2013. The plans included 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. The expected gas production rate would be in the range of 12 MMSCMD, significantly increasing the utilization of existing KG-D6 facilities. Since the approval of the field development plan, the KG-D6 contractor group has completed the concept and front-end engineering design ("FEED") for facilities; completion of detailed engineering for Onshore Terminal (OT) modification works required to handle multiple pressure regimes; final progress stage for well completion design study;

procurement activities commenced for subsea long leads and installation contract for facilities and for rig, tangibles and services. The development of these discoveries is dependent on the future economic viability of the required investments. Refer to "Assets – D6 Block - Gas Sales Pricing" on discussion of the long-term outlook of gas pricing in India.

Satellite Area Development Project

A field development plan for nine (9) Satellite discoveries was submitted for approval in July 2008. At the request of the GOI, an optimized field development plan ("OFDP") for the discoveries was submitted, covering the development of four (4) of the discoveries in the first phase of development and the potential development of the remaining five (5) discoveries in a future phase. The OFDP was approved in January 2012. The development of these discoveries is dependent on the future economic viability of the required investments. In the third quarter of 2013, the GOI issued an order requiring certain portions of the D6 Block contract area be relinquished, including areas around the remaining five (5) discoveries. The contractor group of the D6 Block is contesting the requirement to relinquish these areas and the matter is currently pending for resolution in arbitration.

Other Satellite Discoveries

As per the terms of the PSC, the declarations of commerciality have been submitted for four (4) other satellite ddiscoveries. Approvals for three (3) of these declarations of commerciality was pending resolution of a dispute between the contractor group and the GOI regarding the requirement for drill stem testing ("DST") of the discoveries. In May 2015, GOI came with the policy guidelines on testing requirements giving various options. The joint operating partners selected the option to undertake DST in two (2) of the discoveries and relinquish the third discovery.

The development plans for the R-Cluster, Satellites and Other Satellites fields are subject to certain risk and uncertainties. Refer to "Risk Factors".

MJ Discovery

In March 2013, after a multi-year hiatus, exploration in the D6 Block in India recommenced with the drilling of the MJ-1 exploration well. In May 2013, the joint operating partners announced a significant gas and condensate discovery. The MJ-1 well was drilled to a water depth of 1,024 metres and to a total depth of 4,509 metres exploring the prospectivity of a Mesozoic Synrift Clastic reservoir lying over 2,000 metres below the already producing reservoirs in the Dhirubhai 1 and 3 gas fields. Formation evaluation indicated a gross gas and condensate column in the well of about 155 metres in the Mesozoic reservoirs. The MJ-1 well was drill stem tested at 30.6 MMcf/d of natural gas and 2,121 b/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, was notified to the GOI and the Management Committee of the block. Readers are cautioned that test results are not necessarily indicative of long-term performance or of ultimate recovery.

Subsequent to the completion of the MJ-1 drilling operations, a preliminary technical evaluation was conducted that incorporated all seismic and new well data. Principal findings at the time demonstrated that most parameters for the MJ reservoir exceeded the high end pre-drill estimates. In particular, MJ-1 had considerable thicker reservoir pay than the best case pre-drill assessment of the Company. The pay interval of the MJ-1 well was fully cored and found to be ninety-five (95) percent sand bearing with net pay averaging 125 metres. In addition, the MJ-1 gas water contact, as confirmed by wireline log and MDT data, was at the equivalent depth of a mapped seismic flat spot and a northern structural spill point. The appraisal program for the MJ field commenced with the drilling of MJ-A1 and MJ-A2 appraisal wells. The drilling of MJ-A1, located in the western fault block on the field, was completed in January 2014 and technical evaluation suggested a gross pay interval of 130 meters and pre-drill expectations were largely confirmed. The drilling of MJ-A2, located to target the eastern fault block on the field, was completed in June 2014 and encountered high quality reservoir, similar to the quality and age of the hydrocarbon bearing sections found in MJ-1 and MJ-A1, but the targeted section was wet. Drilling of the third appraisal well, MJ-A3, was completed in the third quarter of Fiscal 2015. The well encountered hydrocarbon at the zone of interest, however the zone was thinner than expected. The results of the three appraisal wells are being integrated into the plans for subsequent development. Enhanced imaging for reservoir characterization is underway and the first phase of conceptual engineering has been completed.

The Company received an independent resources evaluation report for the MJ discovery in the D6 Block effective March 31, 2015 from Deloitte LLP. Deloitte LLP evaluated the contingent resources for the MJ discover in the D6 Block based on available information including the drilling, testing and coring results of the MJ-1 discovery well and the MJ-A1, MJ-A2 and MJ-A3 appraisal wells. Deloitte's best case estimate of gross unrisked contingent resources of 1.4 trillion cubic feet of equivalent (Niko's share 140 Bcfe) relates to the Central (North), Northern and Central (South) fault blocks that were drilled by the MJ-1, MJ-A1, and MJ-A3 wells, based on an estimated areal extent of approximately 24 square kilometers, approximately twice the areal extent of the analogous MA field that is currently producing.

The exploration and development plans with respect to the MJ field are subject to certain risks and uncertainties. See "Risk Factors".

Gas Sales Pricing

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 operating partners, discovered an arm's length price for the sale of gas on a transparent basis with a term of three (3) 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 was capped at $4.20/MMBtu and the formula was declared effective for a period of five (5) years rather than the three (3) years proposed by Reliance. The Company signed numerous gas sales contracts with customers in the fertilizer, power, steel, city gas distribution, liquefied petroleum gas market and pipeline transportation industries, and all of these contracts expired on March 31, 2014.

In June 2013, the Cabinet Committee of Economic Affairs of the GOI approved a pricing formula for domestic gas sales in India, based on the recommendations of the Rangarajan Committee report on "The Production Sharing Contract Mechanism in Petroleum Industry" issued in December 2012. The formula was to be effective April 1, 2014 for a period of five (5) years, with the price to be revised quarterly. The formula was 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.

Based on the formula, the price effective at April 1, 2014 was estimated to be approximately $8.40 / MMbtu, double the price of $4.20 / MMbtu for gas sales from the D6 Block up to March 31, 2014.

In January 2014, the GOI formally announced the Guidelines, which incorporated the formula from June 2013. As per the Guidelines, the pricing formula shall be applicable to all natural gas sales from the D6 Block, subject to submission of bank guarantees related to incremental natural gas revenues from the Dhirubhai 1 and 3 fields. The Company provided bank guarantees to the GOI, as required as security in the case of an adverse outcome to the contractor group of the D6 block of the D6 cost recovery dispute arbitration proceedings. The bank guarantee expired in July 2014 and cash was released from the bank.

There was a continued delay from the GOI in notifying the price after the announcement in January 2014, under protest but in good faith, the contractor group for the D6 Block had kept supplying gas to its customers and the customers have been paying for the gas supplied under the terms of the sales contracts that expired on March 31, 2014 up to October 2014. In May 2014, the contractor group for the D6 Block filed a notice of arbitration to the GOI seeking the implementation of the Guidelines notified while preserving their rights to claim an arms-length market price as required under the PSC.

After three (3) deferrals, in October 2014, the GOI approved the new domestic gas pricing policy for India effective November 1, 2014, and issued the Guidelines, which reflected a pricing formula that had been revised from the pricing formula approved in June, 2013. As per the Guidelines, the gas price is to be calculated based on a volume weighted average of prices in the US, Canada, Europe and Russia based on the twelve (12) month trailing average price with a lag of three (3) months, and is to be determined on a semi-annual basis.

The Guidelines indicate that, subject to certain exceptions, the revised price would be applicable to all natural gas produced from various types of blocks in India including NELP blocks (such as the D6 and NEC-25 blocks in which the Company holds a ten (10) percent interest). One of the exceptions noted in the Guidelines is the Dhirubhai 1 and 3 fields in the D6 Block where a dispute between the contractor group and the GOI on the cost recovery of certain costs is under arbitration. The Guidelines indicate that the contractor group would be paid the earlier price of $4.20 / MMbtu and the difference between the revised price and $4.20 / MMbtu would be credited to a gas pool account and "whether the amount so collected is payable or not to the contractors of this block would be dependent on the outcome of the award of the pending arbitration and any attendant legal proceedings".

In accordance with the new Guidelines, the price for the period of November 1, 2014 to March 31, 2015 increased by approximately thirty-three (33) percent from the $4.20 / MMbtu NCV that natural gas sales had been priced at prior to the adoption of the Guidelines, significantly lower than anticipated when the Facilities Agreement with the lenders had been entered into. The price notified by the GOI for the period of April 1, 2015 to September 30, 2015 decreased by approximately eight (8) percent from the price for natural gas sales from November 1, 2014 to March 31, 2015.

The Guidelines indicate that "For all discoveries after the issuance of these guidelines, in Ultra Deep Water Areas, Deep Water Areas and High Pressure-High Temperature areas, a premium would be given on the gas price determined as per the formula" defined in the Guidelines, with the premium to be "determined as per prescribed procedure." The applicability of the premium to existing undeveloped discoveries in the D6 and NEC-25 blocks, such as the discoveries included in the approved plans of development for the R-Cluster and Satellite Areas, remains to be clarified. The development of these discoveries is dependent on the future economic viability of the required investments.

The development of these discoveries is dependent on the future long-term price outlook for gas sales from these projects and the significant uncertainty in this outlook could mean that the development of these reserves could be deferred and/or material reductions in the Company's reported reserves or future net revenues could result. Refer to additional information and uncertainty over implementation of the gas pricing under "Risk Factors".

Production and Operating Expenses, Profit Petroleum, Royalties and Income Taxes

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 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 operation. Because there are unrecovered costs to date, the GOI's share of profit petroleum has amounted to the minimum level of one (1) 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"Legal Proceedings and Regulatory Actions – Proceedings in India" and "Risk Factors".

The Company currently pays royalty expense of five (5) percent of gross revenue, increasing to ten (10) percent of gross revenue in May 2016 for the Dhirubhai 1 and 3 and MA fields. 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 (7) year income tax holiday commencing from the first year of commercial production and has claimed the tax holiday in the filing of its tax returns since Fiscal 2012. Refer to "Risk Factors – Taxation Risk – Hazira" for full discussion of legal proceeding. Minimum alternate tax ("MAT") is the amount of tax payable in respect of accounting profits. MAT paid can be carried forward for ten (10) years and deducted against regular income taxes in future years. Because of the current gas pricing scenario, the Company estimates that MAT paid in past years may not be fully recoverable within the ten (10) years statutory time limit.

NEC-25 Block, India

The Company has a ten (10) percent working interest in NEC-25, with Reliance, the operator, holding a sixty (60) percent interest and BP holding the remaining thirty (30) percent interest. The original block of 14,535 square kilometers is located adjacent to the east coast of India. The remaining contract area comprises 4,140 square kilometers offshore after relinquishment. Exploration and appraisal drilling has been conducted on NEC-25 resulting in eight (8) discoveries and an integrated block 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. Approval of the integrated block development plan is pending resolution of a dispute between the contractor group and the GOI regarding the requirement for drill-stem testing of the discoveries.

Hazira Field, India

Niko is the operator of and holds a thirty-three (33.33) percent interest in the Hazira Field, located about twenty five (25) kilometers southwest of the city of Surat and covering an area of fifty (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 (1) 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 "Legal Proceedings and Regulatory Actions" for details of contingencies outstanding as at March 31, 2015 regarding the Hazira Field. The Company plans to commence abandonment procedures in Fiscal 2016.

Surat Block, India

The Company holds and is the operator of the twenty four (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 has applied for relinquishment of the block. In Fiscal 2015, the site restoration and abandonment plan has been submitted to the GOI. The Company plans to commence abandonment procedures in Fiscal 2016.

Bangladesh

Block 9, Bangladesh

In September 2003 the Company acquired a sixty (60) percent working interest in the PSC for Block 9. Kris Energy, the operator, holds a thirty (30) percent interest and the remaining ten (10) percent interest is held by BAPEX. Block 9 covers approximately 1,770 square kilometers of land in the central area of Bangladesh surrounding the capital city of Dhaka. Natural gas and condensate production for the Bangora field in Block 9 commenced in May 2006 and gas is transported from four (4) 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 66 MMcf/d in Fiscal 2015 after completion of two (2) workovers in Fiscal 2014. A scheduled plant turnaround was completed in October 2014 and plant compression facilities came on-line in the third quarter of Fiscal 2015.

The Company has signed a GPSA including a price of $2.32/Mcf, which expires at the earliest of the end of commercial production, at expiry of the PSC (March 31, 2026) and twenty-five (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 operations. During the Fiscal 2015, the GOB's share of profit petroleum increased from the minimum level of thirty-four (34) percent of gross revenue to over forty five (45) percent as all the past unrecovered allowable costs were fully recovered based on the profit petroleum provisions of the PSC.

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

Other Countries

The Company continues to evaluate options to capture value from its exploration assets through asset sales, farm-outs and other arrangements, while maintaining optionality. Furthermore, the Company has extended and intends to reschedule its exploration commitments in various blocks.

Indonesia

The table below indicates the operator, the location of, the award date, Niko's working interest and the size of the block, for the Indonesian Blocks as at March 31, 2015.

Block Name	Operator	Offshore Area	Award Date	Working Interest	Area (Square Kilometers)
East Bula	Niko	Seram NE	Nov. 2009	55%	4,516
South East Seram	Niko	Papua SW	Dec. 2011	100%	8,217
Sunda Strait I	Niko	Sunda Strait	May 2010	100%	6,960
Bone Bay	Niko	Sulawesi SW	Nov. 2008	100%	2,979
Kumawa	Niko	Papua SW	May 2009	100%	5,004
Semai V	Niko	Papua SW	Nov 2008	100%	2,364
Seram	Niko	Seram North	Nov. 2008	55%	2,987
South East Ganal	Niko	Makassar Strait	Nov. 2008	100%	2,918
South Matindok	Niko	Sulawesi NE	Nov. 2008	100%	3,110
West Sageri	Niko	Makassar Strait	Nov. 2008	100%	2,986
Obi(2)	Niko	Papua W	Nov. 2011	42%	8,057
Aru(2)	Niko	Papua SW	July 2012	60%	8,054
Halmahera-Kofiau(2)	Niko	Papua W	Nov. 2009	80%	3,695
North Ganal(2)	Eni	Makassar Strait	Nov. 2011	18.5%	2,432
Kofiau(2)	Niko	West Papua	May 2009	100%	5,000
North Makassar Strait(2)	Niko	Makassar Strait	Nov. 2009	30%	1,340
West Papua IV(2)	Niko	Papua SW	Nov. 2009	49.9%	3,831
Cendrawasih(1)	Niko	Papua NW	May 2009	70%	4,991
Cendrawasih Bay III(1)	Niko	Papua NW	May 2010	50%	4,689
Cendrawasih Bay IV(1)	Niko	Papua NW	May 2010	50%	3,904
Halmahera II(1)	Statoil	Papua W	Dec. 2011	20%	8,215

(1) Relinquished blocks that are subject to government approval.

(2) The Company executed a definitive agreement for the sale of the Company's interest in seven (7) Indonesian PSCs in October 2014, of which four (4) PSCs (Aru, Kofiau, Halmahera Kofiau, West Papua IV) were subsequently sold in April 2015. The sales of the Company's interest in two (2) additional PSCs (North Ganal and North Makassar Strait) are subject to satisfaction or waiver of the remaining conditions precedent. Ophir has decided not to proceed with the acquisition of the Company's interest in the Obi PSC.

The minimum work commitments represent the amounts the GRI 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.

For six (6) PSCs in Indonesia that had commitments due in November 2014 and one (1) PSC that had commitments due in May 2015, the Company requested amendments to the PSCs to extend the initial exploration period to ten (10) years, and related extensions to the commitment dates. Extensions have not been granted and certain of the Company's subsidiaries have recorded liabilities of $117 million for these unfilled exploration work commitments as at March 31, 2015.

Trinidad and Tobago

The table below indicates the operator, the location of, the award date, the Company's working interest and the size of the block, for the Trinidad Blocks as at March 31, 2015.

Exploration Area	**Operator**	**Location**	**PSC Date**	**Working Interest**	**Area (Square Kilometers)**
Guayaguayare - Shallow Horizon[(1)(2)]	Niko	Onshore/Offshore	July 2009	65%	1,134
Guayaguayare - Deep Horizon[(1)(2)]	Niko	Onshore/Offshore	July 2009	80%	1,190
Block 4(b)[(2)]	Niko	Offshore	April 2011	100%	753
Block NCMA 2	Niko	Offshore	April 2011	56%	1,019
Block NCMA 3[(2)]	Niko	Offshore	April 2011	80%	2,106
MG Block	Niko	Offshore	July 2007	70%	223

(1) In January 2014, the Company farmed out fifty (50) percent of the Company's interest in the Guayaguayare Shallow and Deep PSCs to Range. Subsequent to March 31, 2015, the Company executed agreements to sell its entire interests in the Guayaguayare Shallow and Deep PSCs to subsidiaries of Range, effectively amending the terms of previously executed farm-out agreements. Under the sale agreements, the Company will sell its interests in the PSCs in exchange for the assumption of existing liabilities and commitments under the PSCs and for potential future payments that are contingent on certain future events in the PSCs. Approval from the GOTT is pending. Working interest in the table does not reflect the change in working interest.

(2) In October 2014 the Company submitted for relinquishment of certain areas of its blocks in Trinidad. Approval from GOTT is pending.

The minimum work commitments represent the amounts the GOTT 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.

Work commitments under the Trinidad PSCs are backed by parent guarantees. Unfulfilled exploration work commitments in Trinidad of $75 million have been recorded as at March 31, 2015 related to extensions to the deadlines for commitments that have not been received for certain PSCs in Trinidad.

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 earned seventy-five (75) percent participating interest in the block and was the operator of this block. In August 2013, the Company farmed out a forty (40) percent interest in the Grand Prix Block to OMV, an integrated international oil and gas company. In July 2014, the Company transferred its remaining 35 percent interest in the Grand Prix Block in Madagascar to an existing partner in exchange for potential future payments to the Company that are contingent on certain future events in the block.

Pakistan

The Company applied for relinquishment of the four (4) blocks it holds in Pakistan, located in the Arabian Sea near the city of Karachi and covering an area of 9,921 square kilometers in February 2013, which is pending approval from the Government of Pakistan.

Brazil

In September 2013, the Company acquired thirty (30) percent interests in two (2) contract areas in Brazil, covering 985 square kilometers. Both the blocks are in the first exploration period of five (5) years. The Company's share of the minimum work commitments for the acquisition and processing of seismic for the two (2) blocks is $3 million to be spent by September 2018. Work commitments under the Brazil PSCs are backed by parent guarantees.

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 or JVA or relinquishment of part of a contract area under a PSC 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 immoveable 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) The exploration period consist of three (3) consecutive exploration phases not exceeding seven (7) consecutive years in aggregate, with the first phase not exceeding three (3) years and the second and third phases not exceeding two (2) years each. Subsequent to a commercial discovery, the petroleum mining lease may be obtained for a period of twenty (20) years, which may be extended for further five (5) years by mutual agreement.

(b) 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, ninety (90) percent of revenue can be used to recover costs. Under the terms of the PSCs, the GOI is entitled to a ten (10) percent interest in the profit oil and natural gas produced if the participants have recovered less than one-hundred-fifty (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.

(c) A specific work commitment for each block, which would include reprocessing existing 2D seismic, shooting new 2D and 3D seismic and drilling one (1) exploration well in the first phase of the work commitment. For the D6 Block, subsequent work phases are optional and would include additional seismic and three (3) exploration wells in the second phase and four (4) exploration wells in the third phase for the D6 Block. For NEC-25 subsequent work phases are optional and would include additional seismic and two (2) exploration wells in the second phase and four (4) exploration wells in the third phase for the D6 Block. All minimum work commitments for the D6 Block and NEC-25 block have been satisified.

(d) 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.

(e) Subject to an extension of time approved by the GOI, the Contractors may retain the greater of seventy-five (75) percent of the original contract area or the entire development area and discovery area and relinquish up to twenty five (25) percent at the end of the first exploration phase of the PSC. The Contractors shall retain the greater of fifty (50) percent of the original contract area or the entire development area and discovery area and relinquish the balance areas at the end of the second phase. At the third exploration phase, the Contractors shall retain only development areas and relinquish the balance areas.

(f) Following a discovery, the Contractor is required to run tests to determine whether the discovery is of potential commercial interest. If the Contractor determines to conduct a drill stem test or production test, in open hole or through perforated casing, the Government shall have the right to have a representative present during testing. The PSC does not have a specific requirement to conduct a drill stem test and doing so is at the Contractor's election.

(g) Upon approval of a development plan and designation of a development area by the GOI, the joint operating 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 operating 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 (3) years subsequent to the year for which the proposed work program and budget relate.

(h) Once commercial production has commenced, and on an annual basis thereafter, the joint operating 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 operating partners, as approved by the management committee, and will assume operations are conducted in accordance with good international petroleum industry practices and minimizing 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.

(i) Payment of royalty to the GOI for offshore areas falling in water depth greater than four hundred (400) metres is five (5) percent of the wellhead value of crude oil and natural gas for the first seven (7) years from the date of commencement of production in the field and ten (10) percent thereafter.

(j) A seven (7) 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.

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

(l) Any party comprising the contractor may assign, or transfer, a part or all of its participating interest, with the prior written consent of the government.

(m) The Contractor shall endeavour to sell all Natural Gas produced and saved from the Contract Area at arms-length prices to the benefits of Parties to the Contract. Natural Gas produced from the Contract Area shall be valued for the purposes of the contract as follows:

   i. Gas which is used as per Article 21.2 or flared with the approval of the Government or re-injected or sold to the Government shall be ascribed a zero value;

   ii. Gas which is sold to the Government or any other Government nominee shall be valued at the prices actually obtained; and

   iii. Gas which is sold or disposed of otherwise than in accordance with paragraph (i) or (ii) shall be valued on the basis of competitive arms-length sales in the region for similar sales under similar conditions.

(n) The formula or basis on which the prices shall be determined shall be approved by the Government prior to the sale of Natural Gas to the consumers/buyers. For granting this approval, Government shall take into account the prevailing policy, if any, on pricing of Natural Gas including any linkages with traded liquid fuels, and it may delegate or assign this function to a regulatory authority as and when such an authority is in existence.

Certain of Niko's PSCs, including the PSC governing the D6 Block, may be terminated upon certain insolvency events, including a filing under the CCAA or other debtor protection laws, or other defaults. See the risk factors under the heading "Risk Factors" 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 twenty (20) years for oil production and of twenty-five (25) years for natural gas production.

(b) Subject to an extension of time approved by the GOB, a requirement to relinquish twenty-five (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 forty-five (45) percent per calendar year of all available natural gas and condensate produced. Costs not recoverable in a particular year shall be carried forward for recovery in the next succeeding years until fully recovered. Profit petroleum is to be shared as per below:

Profit Natural Gas	**During Cost Recovery**		**After Cost Recovery**	
Production Tranches	Petrobangla Share (%)	Contractor Share (%)	Petrobangla Share (%)	Contractor Share (%)
Up to 150 mmscfd	61	39	66	34

Profit Condensate	**During Cost Recovery**		**After Cost Recovery**	
Production Tranches	Petrobangla Share (%)	Contractor Share (%)	Petrobangla Share (%)	Contractor Share (%)
Up to 3,000 bblsd	65	35	70	30

(d) Participants may produce annually a total volume of natural gas equal to up to seven (7) 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 seventy five (75) percent of the arithmetic daily average of Platt's Oilgram quotations of high sulphur fuel oil 180 CST, FOB Singapore for the six (6) months ending on the last day of the second month preceding the start of the particular quarter (with a floor price, prior to the twenty five (25) percent discount, of $70 per metric tonne and a ceiling price, prior to the twenty-five (25) percent discount, of $120 per metric tonne) plus a further one (1) 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 twenty-five (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 fifteen (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 (5) years after first delivery of crude oil, in the amount of twenty five (25) percent of the contractors entitlement of crude oil produced at twenty five (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 twenty five (25) percent of the quantity of natural gas proven reserves multiplied by the contractor's entitlement.

(d) A term of thirty (30) years, including an initial term of the exploration period of six (6) years, extendable for a maximum period of four (4) years. The Contractor has the option to terminate at the end of the third contract year.

(e) The sharing in the profit petroleum among the participants and BPMIGAS; under the terms of the various PSCs, eighty (80) percent of revenues can be used to recover costs; on the revenues not used to recover costs, BPMIGAS's share varies by PSC. For all PSCs, with exception of South East Seram, the Contractor is entitled to receive the following:

	Profit Natural Gas	Profit Crude Oil
All PSCs	71.43 percent	62.5 percent
South East Seram PSC	66.67 percent	58.33 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 ten (10) percent to thirty (30) percent of the contract area after the first three (3) contract years and an additional fifteen (15) percent if the firm commitment has not been completed, (ii) relinquish additional areas in excess of twenty (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 commitments for geological and geophysical activities, 2D and 3D seismic acquisition, and exploration drilling in each of the six (6) years of the exploration period are bid specific to each PSC. The firm commitments are considered to be the first three (3) years of work.

(h) Twenty-five (25) percent of the original contract area to be relinquished at the end of the third contract year. Additional fifteen (15) percent of the original contract area must be relinquished if the Contractor failed to complete the firm commitment. The Contractor is permitted to retain the greater of twenty (20) percent of the original contract area or the area related to petroleum discoveries at the end of the sixth contract year.

(i) The Contractor is required to bid the following bonuses: signature bonus due upon signing the PSC; equipment and services bonuses due within thirty (30) days on signing the PSCs; and production bonuses payable upon reaching cumulative production levels of 25 mmboe, 50 mmboe and 75 mmboe. These bonuses are not recoverable.

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

(k) The Contractor is required to submit a development plan within three (3) years of notification of a discovery, however, a two (2) year extension may be requested for deep water or natural gas discoveries. The Contractor has five (5) years after the end of the exploration period to commence development.

Terms of the Trinidad and Tobago PSCs

The material provisions of the PSCs for the remainingTrinidad 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 (60) percent of revenue can be used to recover costs for Guayaguayare Area. For the Guayaguayare Area exploration costs may be recovered as they are expensed; development and production capital costs may be recovered over four (4) years with forty (40) percent recoverable in the first year and twenty (20) percent recoverable in each of the next three (3) years; and operating and administrative costs are recovered in the year they are incurred. Fifty (50) 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 operating partners and the GTT on a monthly basis ranging from fourteen (14) percent to sixty-three (63) percent for the Guayaguayare Area and fifty (50) percent to seventy-five (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). Royalty rates in the MG Block are twelve (12) percent on natural gas and crude oil.

(d) An exploration period for the Guayaguayare Area of six (6) contract years divided into a first phase of four (4) years, an optional second phase of one (1) year and an optional third phase of one (1) year; for an exploration period for Block NCMA 2 of six (6) contract years divided into a first phase of five (5) years, and optional second phase of six (6) months and an optional third phase of six (6) months; for an exploration period for Block NCMA 3 of six (6) contract years divided into a first phase of three (3) years, and optional second phase of two (2) years and an optional third phase of one (1) year; for an exploration period for Block 4(b) of six (6) contract years divided into a first phase of three (3) years, an optional second phase of two (2) years and an optional third phase of one (1) year; and for an exploration period for the MG Block of six (6) contract years.

(e) A requirement under the first phase of the exploration period to acquire and process 130 and 200 square kilometers of 3D seismic onshore and offshore, respectively, and drill two (2) onshore wells and one (1) offshore well during the first phase of the exploration period, drill one (1) onshore well and one (1) offshore well during the second phase of the exploration period and drill four (4) onshore wells and one (1) 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 kilometers of 3D seismic and drill three (3) wells, drill one (1) well during the second phase of the exploration period and drill one (1) 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 kilometers of 3D seismic and drill one (1) well, drill one (1) well under the second phase of the exploration period and drill one (1) 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 kilometers of 3D seismic and drill one (1) well, drill one (1) well under the second exploration period and drill one (1) well under the third exploration period for Block 4(b); and that the Company is required to acquire and process 200 line kilometers of 2D seismic and drill one (1) well for the MG Block.

(f) Subject to an extension of time approved by the government, a requirement to (i) relinquish twenty-five (25) to forty (40) percent of the block at the end of the first phase of the exploration period, (ii) cumulatively relinquish not less than fifty (50) percent of the block by the end of the second phase of the exploration period, 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 the Guayaguayare 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 and Block 4(b).

Terms of the Brazil Concession Contracts

The material provisions of the concession contracts for the two (2) contract areas in Brazil include:

(a) Exclusive development rights within the concession area and ownership of measured hydrocarbons at the metering point, with the right to dispose of such hydrocarbons, including by way of export (subject to obtaining certain permits and certain restrictions in the event of emergency situations in the domestic market).

(b) An exploratory period of seven (7) contract years is divided into five (5) plus two (2) years: a first phase of five (5) years, and an optional second phase of two (2) years. The exploratory period may be extended in accordance with the concession contract if an exploratory well has been drilled but has not yet been assessed at the end of an exploration phase. During the first phase of the concession contracts, Niko is required to acquire and process at least 324 square kilometers of 3D seismic in respect of each exploration concession area. The Company has the option to elect the second phase if the Company chooses to do so once all the requirements of the first phase have been met and agreed by ANP. The second phase requires one (1) well per concession to a specific stratigraphic objective as outlined in the exploration programme of the concession.

(c) At any time within the exploration phase, the areas of the concession can be totally reverted by notifying ANP formally and in writing. Areas of interest can be carved out in consultation with ANP, with a set timeframe, at the end of the period.

(d) Upon a declaration of commerciality and acceptance by ANP of the development plan, production from the applicable field is permitted for a duration of twenty-seven (27) years, subject to extension by ANP or Niko. At the end of the production phase, the field must be returned to ANP with the assets necessary to continue operations in the relinquished area and all other assets must be removed at the sole expense of Niko.

(e) The operator must hold at least thirty (30) percent of the contract share throughout the term of the concession contract.

(f) In addition to the signature bonus paid at the time of entry into the concession contracts, Niko is required to pay royalties (ten (10) percent of the production of oil and natural gas), taxes, a special participation in an amount equivalent to one (1) percent of the gross revenues of production for a field for research, development and innovation in areas of interest and topics relevant to the petroleum, natural gas and biofuel sectors, payment for the occupation or retention of the lands and payment to the owners of the land of participation equivalent to one (1) percent of the oil and natural gas production. Niko is also required to maintain certain commitments for local goods and services during the term of the concession contract.

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 Deloitte, and is effective March 31, 2015. The preparation date of the information regarding reserves in the Statement was June 10, 2015 for 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 Deloitte Report for the D6 Block and NEC-25 in India and Block 9 in Bangladesh, based on forecast price assumptions presented in accordance with NI 51-101.

There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The 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. For the India gas reserves, Deloitte has estimated prices based on the New Domestic Natural Gas Guidelines discussed under "Assets – India", commencing on an effective date of November 1, 2014.

As at March 31, 2015, the Company's material reserves were located in India (D6 Block and NEC-25) and Bangladesh (Block 9) with material production in India (D6 Block) and Bangladesh (Block 9). The Company also has production from the Hazira Field in India. The Company believes that the reserves attributable to its interest in the Hazira Field in India constitutes less than one (1) percent of the Company's total reserves and therefore these reserves 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 the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3 is attached hereto as Appendix "B".

The following tables detail the Company's estimated aggregate gross and net reserves for both the D6 Block and NEC-25 in India, and Block 9 in Bangladesh, estimated using forecast prices and costs, as well as the estimated aggregate net present value of future net revenue attributable to the reserves (both before and after future income tax expenses), estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves
Forecast Prices and Costs As At March 31, 2015

	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	603	545	51,686	46,691	96	86
Bangladesh	-	-	111,549	59,822	324	164
Total Proved Developed Producing	603	545	163,235	106,513	420	250
Proved Developed Non-Producing						
India	-	-	3,409	3,091	-	-
Bangladesh	-	-	12,815	7,369	37	20
Total Proved Developed Non-Producing	-	-	16,224	10,460	37	20
Proved Undeveloped						
India	23	20	10,076	9,025	3	4
Bangladesh	-	-	21,154	14,139	61	40
Total Proved Undeveloped	23	20	31,230	23,164	65	43
Total Proved						
India	625	565	65,171	58,807	99	90
Bangladesh	-	-	145,518	81,330	422	224
Total Proved	625	565	210,689	140,138	521	314
Total Probable						
India	297	262	297,873	274,089	49	43
Bangladesh	-	-	28,263	17,033	82	47
Total Probable	297	262	326,136	291,122	131	90
Total Proved Plus Probable						
India	922	827	363,044	332,897	148	133
Bangladesh	-	-	173,781	98,363	504	272
Total Proved Plus Probable	922	827	536,825	431,260	652	405

(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 GOB.

Summary of Net Present Values of Future Net Revenues
Forecast Prices and Costs as at March 31, 2015

Reserves Category (MM$)	Before Deducting Income Taxes Discounted At 0%	5%	10%	15%	20%	After Deducting Income Taxes Discounted At[(2)] 0%	5%	10%	15%	20%	Unit Value Before Income Tax Discounted at 10%/year (US$/boe)[(3)]
Proved Developed Producing											
India	60	58	57	55	53	60	58	57	55	53	6.72
Bangladesh	64	55	49	44	39	64	55	49	44	39	4.80
Total Proved Developed Producing	124	113	105	98	93	124	114	105	98	93	5.67
Proved Developed Non-Producing											
India	7	7	6	6	5	7	7	6	6	5	11.84
Bangladesh	7	6	4	3	3	7	6	4	3	3	3.41
Total Proved Developed Non-Producing	15	12	10	9	8	15	12	10	9	8	5.88
Proved Undeveloped											
India	8	6	3	1	-	8	6	3	1	-	2.15
Bangladesh	13	11	9	8	6	13	11	9	8	6	3.71
Total Proved Undeveloped	21	16	12	9	6	21	16	12	9	6	3.10
Total Proved											
India	76	71	66	62	58	76	71	66	62	58	6.31
Bangladesh	84	71	62	54	49	84	71	62	54	49	4.49
Total Proved	160	142	128	116	107	160	142	128	116	107	5.27
Total Probable											
India	458	226	99	28	(10)	386	179	66	5	(28)	2.15
Bangladesh	16	11	8	6	5	16	11	8	6	5	2.82
Total Probable	473	237	107	34	(6)	402	190	74	11	(23)	2.19
Total Proved Plus Probable											
India	534	297	165	90	48	462	249	132	66	30	2.92
Bangladesh	99	82	70	61	53	99	82	70	61	53	4.20
Total Proved Plus Probable	633	379	235	151	101	562	332	202	127	83	3.21

(1) These values reflect reductions for the estimates for profit petroleum amounts that will be payable to the GOI and the GOB, cash outflows for the funding of abandonment obligations, and for the D6 Block, cash outflows reflected for the lease of the FPSO used in the MA field.

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

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

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 and Block 9 in Bangladesh, estimated using forecast prices and costs and calculated without discount:

Future Net Revenue (Undiscounted)
As At March 31, 2015

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(1)	344	(33)	(169)	(30)	(37)	76	-	76
Bangladesh	372	(167)	(94)	(24)	(2)	84	-	84
Total	716	(200)	(263)	(54)	(40)	160	-	160
Total Proved Plus Probable								
India(1)	2,091	(191)	(576)	(696)	(95)	534	(71)	462
Bangladesh	445	(196)	(110)	(36)	(3)	99	-	99
Total	2,536	(387)	(686)	(731)	(98)	633	(71)	562

(1) Refer to "Assets – India" for a discussion on the India gas pricing assumptions. Revenue as presented above is the estimated price including the marketing fee currently paid by customers.

(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".

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

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 and Block 9 in Bangladesh, estimated using forecast prices and costs and calculated using a discount rate of ten (10) percent:

Future Net Revenue by Production Group As At March 31, 2015			
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) Natural gas(2)	13 114	5.27
Total Proved Plus Probable	Light and medium oil(1) Natural gas(2)	17 217	3.21

(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 and the GOB.

Pricing Assumptions

The following table details the reference prices and inflation rate assumptions as of March 31, 2015 utilized by Deloitte in the Deloitte Report for estimating reserves data disclosed above under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data". Deloitte is an independent qualified reserves evaluator and auditor.

Summary of Pricing and Inflation Rate Assumptions As of March 31, 2015 Forecast Prices and Costs for India					
Fiscal Year	**India Crude Oil ($US/bbl)(2)**	**India NGL ($US/bbl)(2)**	**India Natural Gas ($US/MMbtu)(2)**		**Inflation Rate (%/Year)(3)**
Forecast			GCV	NCV	
2016	61.80	44.00	4.28	4.76	2
2017	71.49	53.69	3.59	3.99	2
2018	78.68	60.88	3.89	4.32	2
2019	84.00	66.20	4.21	4.68	2
2020	87.87	70.07	4.48	4.98	2
Average thereafter	+2%	+2%	+2%		2

(1) Prices are shown in current dollars on a raw received basis.
(2) Refer to "Assets – India" for a discussion on the India gas pricing assumptions.
(3) Inflation applied to operating and capital expenditures only.

Summary of Pricing and Inflation Rate Assumptions As of March 31, 2015 Forecast Prices and Costs for Block 9			
Fiscal Year	**Block 9 NGL ($US/bbl)**	**Block 9 Natural Gas ($US/Mcf)**	**Inflation Rate (%/Year)[(3)]**
Forecast			
2016	61.35	2.32	2
2017	70.87	2.32	2
2018	77.91	2.32	2
2019	83.12	2.32	2
2020	86.91	2.32	2
Average thereafter	+2%	2.32	2

(1) The NGL and natural gas prices shown in the table were provided by Deloitte based on discussions with the Company, contractual agreements and sales data provided by the Company to Deloitte.
(2) The forecast inflation rate provided by Deloitte 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 2015 were $92.48/bbl for oil, $69.78/bbl for NGLs and $4.65/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 2015 were $82.16/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, 2014 and as at March 31, 2015 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type — India Forecast Prices and Costs									
	Light and Medium Oil[(1)]			**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, 2014	965	267	1,232	252,682	157,713	410,394	164	43	207
Technical Revisions	20	(135)	(115)	11,833	(54,043)	(42,210)	18	(47)	(29)
Economic Factors	(164)	164	-	(199,328)	194,203	(5,125)	(53)	53	-
Production	(196)	-	(196)	(15,348)	-	(15,348)	(30)	-	(30)
March 31, 2015	625	297	922	65,171	297,873	363,044	99	49	148

(1) Oil volumes reported as at March 31, 2015 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, 2014 and as at March 31, 2015 estimated using forecast prices and costs:

Reconciliation of Company Gross Reserves by Product Type — Bangladesh Forecast Prices and Costs						
	Associated and Non-Associated Gas			**NGLs**		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved plus Probable (Mbbl)**
March 31, 2014	125,434	44,033	169,466	352	123	475
Extensions and Improved Recovery	34,668	(17,102)	17,566	115	(45)	70
Technical Revisions	8,715	1,332	10,047	25	4	29
Production	(23,298)	-	(23,298)	(69)	-	(69)
March 31, 2015	145,518	28,263	173,781	422	82	504

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 (3) most recent financial years and, in the aggregate, before that time:

Undeveloped Reserves First Attributed Forecast Prices and Costs			
	Light and Medium Oil Gross (Mbbl)	**Natural Gas Gross (MMcf)**	**NGL Gross (Mbbl)**
Proved Undeveloped			
2015	-	4,974	14
2014	-	-	-
2013	424	289,358	105
Prior thereto	-	-	-
Probable Undeveloped			
2015	148	87,732	25
2014	-	15,108	-
2013	728	224,975	81
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 Dhirubhai 1 and 3 fields in the D6 Block in India are expected to be developed over the next one (1) to two (2) years. The probable undeveloped reserves for the R-Series and Satellite Area in the D6 Block could be developed over the next five (5) to six (6) 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. Proved undeveloped reserves attributed to these fields were reclassified to probable undeveloped reserves due to the uncertainty in the economic viability of the development projects at the price assumed in the reserve evaluations of these fields. Refer to "Assets – India – Gas Sales Pricing".

The probable undeveloped reserves for the J-Series in NEC-25 in India could be developed over the next five (5) 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. Proved undeveloped reserves attributed to these fields were reclassified to probable undeveloped reserves due to the uncertainty in the economic viability of the development projects at the price assumed in the reserve evaluations of these fields. Refer to "Assets – India – Gas Sales Pricing".

The proved undeveloped and probable undeveloped reserves in Block 9 in Bangladesh are expected to be developed over the next two (2) years with additional drilling.

Additional undeveloped discoveries in the D6 Block and NEC-25 in India, the undeveloped Chattak and developed Feni properties in Bangladesh, the Indonesian Blocks, and the Trinidad Blocks do not have reserves, as defined in NI 51-101, attributable to them.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that may affect the components of the reserves data in the Statement, see the Company's management's discussion and analysis of financial condition, results of operations and cash flows for Fiscal 2015 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 and Block 9 in Bangladesh attributable to proved reserves and proved plus probable reserves (both estimated using undiscounted and forecast prices and costs):

Future Development Costs				
	Total Proved Reserves		**Total Proved Plus Probable Reserves**	
Calendar Year	**India**	**Bangladesh**	**India**	**Bangladesh**
2015	25	16	25	16
2016	5	2	5	9
2017	-	6	1	11
2018	-	-	153	-
2019	-	-	303	-
Remainder	-	3	209	3
Total Undiscounted	30	27	696	39

(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 in India and Bangladesh is expected to be derived from the Company's unrestricted cash, restricted cash, internally generated cash flow, potential proceeds from asset sales, farm-outs and other arrangements, and potential proceeds from future equity or debt issuances. 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. Refer to "Description of Capital Structure" for details of the Company's debt obligations.

Oil and Gas Wells

The following table summarizes the Company's interests in India and Bangladesh as at March 31, 2015, in oil and gas wells:

Producing and Non-Producing Wells As at March 31, 2015						
	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Producing[1]						
India - offshore	2.0	0.7	13.0	1.5	15.0	2.2
India - onshore	-	-	5.0	1.7	5.0	1.7
Bangladesh - onshore	-	-	4.0	2.4	4.0	2.4
Total Producing	2.0	0.7	22.0	5.6	24.0	6.3
Non-Producing[2][3]						
India - offshore	3.0	0.3	19.0	4.0	22.0	4.3
India - onshore	-	-	29.0	17.7	29.0	17.7
Bangladesh - onshore	-	-	4.0	3.6	4.0	3.6
Total Non-Producing	3.0	0.3	52.0	25.3	55.0	25.6

(1) Includes wells that are temporarily shut-in but which are capable of production. See "Assets".
(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 four (4) gross (2.3 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, 2015				
	Unproved Properties (Acres)		Expiring in Year Ended March 31, 2016 (Acres)	
Location	Gross	Net	Gross	Net
Bangladesh	533,213	359,201	-	-
Brazil	243,322	72,997	-	-
India[1]	1,283,689	128,369	5,928[1]	5,928[1]
Indonesia[2][3]	14,257,887	9,513,430	10,717,401[2][3]	6,434,846[2][3]
Pakistan[4]	-	-	-	-
Trinidad	860,842	623,889	-	-
Total	17,178,953	10,697,884	10,723,329	6,440,774

(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 portions of several of its blocks in Indonesia, or has applied for extensions to the exploration periods for acreage that will expire during the year (4,960,501 acres). The Company expects to be granted approval from the GRI as applicable.
(3) The Company sold four (4) of its PSCs in Indonesia in April 2015 and the sale of two (2) remaining PSCs are subject to the satisfaction or waiver of the remaining conditions precedent (5,757,076 acres). The Company expects to be granted approval from the GRI as applicable.
(4) The Company has applied to relinquish all four (4) Pakistan Blocks in February 2013 and the entire 2,450,460 acres of the four (4) Pakistan Blocks are excluded from above. Approval of Government of Pakistan is pending.

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 $37 million ($14 million discounted at ten (10) percent). The undiscounted costs for total proved plus probable reserves amounts to $95 million ($14 million discounted at ten (10) percent). A total of $8 million of abandonment and reclamation costs ($7 million discounted at ten (10) percent 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 (3) fiscal years, which are primarily related to the Hazira Field and the Surat Block in India.

Costs Incurred

For Fiscal 2015, the Company incurred the following costs on its properties:

MM$	Property Acquisition Costs: Proved Properties	Property Acquisition Costs: Unproved Properties	Exploration Costs	Development Costs	Total Costs
Bangladesh	-	-	-	3	3
India	-	-	16	32	48
Indonesia	-	-	3	-	3
Trinidad	-	-	8	-	8
Brazil	-	-	2	-	2
Total		-	29	35	64

The following table sets forth the number of exploration and development wells the Company completed during Fiscal 2015:

	Exploratory Wells(1)		Development Wells	
	Gross	Net	Gross	Net
India				
Gas Wells	1.0	0.1	-	-
Oil Wells	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Holes	1.0	0.1	-	-
Total	2.0	0.2	-	-

(1) Includes appraisal wells. Does not include wells that were drilling or under evaluation as at March 31, 2015.

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 actual production volumes, average daily production volumes, average price received, royalties, profit petroleum, production costs and the resulting netbacks for the periods indicated as at March 31, 2015:

Actual Production
Working Interest to Niko by Field and Product Type
Year Ended March 31, 2015

	D6 Block, India	Hazira Field, India	Block 9, Bangladesh	Total
Light and Medium Crude Oil (Mbbl)	197	-	-	197
NGL (Mbbl)	31	11	69	111
Natural Gas (MMcf)	15,348	568	23,298	39,214
Total (MMcfe)	16,716	634	23,712	41,062

(1) India volumes include production from the Hazira Field.

Average Daily Production Working Interest to Niko Year Ended March 31, 2015				
	Quarter Ended			
	June 30, 2014	September 30, 2014	December 31, 2014	March 31, 2015
India[(1)]				
Oil (bbls/d)	577	553	514	507
NGL (bbls/d)	135	99	101	132
Natural Gas (Mcf/d)	46,873	44,842	42,266	40,411
India - Mcfe/d	51,143	48,752	45,957	44,245
Bangladesh				
Oil (bbls/d)	-	-	-	-
NGL (bbls/d)	193	181	178	201
Natural Gas (Mcf/d)	64,691	63,723	61,915	65,029
Bangladesh - Mcfe/d	65,851	64,811	62,981	66,236
Total - Mcfe/d[(2)]	116,993	113,563	108,938	110,481

(1) India volumes include production from the D6 Block and the Hazira Field.
(2) Figures may not add up due to rounding.

Netback History Natural Gas, Oil and NGL Year Ended March 31, 2015				
	Quarter Ended			
	June 30, 2014	September 30, 2014	December 31, 2014	March 31, 2015
India[(1)]				
Average Price Received (US$/Mcfe)	5.63	5.07	5.23	5.59
Royalties (US$/Mcfe)[(1)]	(0.26)	(0.25)	(0.24)	(0.30)
Profit Petroleum (US$/Mcfe)[(1)]	(0.12)	(0.07)	(0.06)	(0.06)
Production Costs (US$/Mcfe)	(1.45)	(1.59)	(1.44)	(1.78)
Netback (US$/Mcfe)	3.80	3.15	3.48	3.46
Bangladesh[(1)]				
Average Price Received (US$/Mcfe)	2.59	2.56	2.48	2.43
Royalties (US$/Mcfe)[(1)]	-	-	-	-
Profit Petroleum (US$/Mcfe)[(1)]	(0.87)	(1.43)	(1.15)	(1.27)
Production Costs (US$/Mcfe)	(0.39)	(0.38)	(0.36)	(0.47)
Netback (US$/Mcfe)	1.33	0.75	0.97	0.69

(1) Under the terms of the gas sales contracts that are in place with respect to the Company's natural gas production from the Hazira Field in 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 were in place with respect to the Company's natural gas production from the D6 Block in India until March 31, 2014, the purchasers of natural gas pay a marketing margin over and above the contracted price. Effective November 1, 2014, customers of the D6 Block in India pay for natural gas at the new gas price of $5.05 / MMBtu GCV, which equates to approximately $5.61 / MMBtu NCV for the period of November 1, 2014 to March 31, 2015 under the Guidelines. Average price received as presented above is the contracted price plus the marketing fee plus the amount of royalties levied by the GOI for Hazira. 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.

Production Estimates

The following table provides the Company's estimated volume of production for fiscal 2016 from its India and Bangladesh properties derived from the Deloitte Report, respectively:

Estimated Production Forecast Prices and Costs Estimated production for the year ended March 31, 2016				
	Proved Reserves (Gross)	**Proved Reserves (Net)[(1)]**	**Proved Plus Probable Reserves (Gross)**	**Proved Plus Probable Reserves (Net)[(1)]**
India, D6 Block				
Natural Gas (MMcf)	16,113	15,146	17,943	16,867
NGL (Mbbl)	26	25	27	25
Light and Medium Crude Oil (Mbbl)	164	154	169	159
India - MMcfe	17,253	16,220	19,119	17,971
Bangladesh, Block 9				
Natural Gas (MMcf)	23,849	14,494	23,852	14,496
NGL (Mbbl)	69	42	69	42
Bangladesh - MMcfe	24,263	14,746	24,266	14,748
Total - MMcfe	**41,516**	**30,966**	**43,385**	**32,719**

(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.

PERSONNEL

Recent Updates

Refer to "Corporate – Personnel Updates" for changes in management, directors and officers during Fiscal 2014 and Fiscal 2015.
The following table shows the distribution of employees, contractors and consultants of the Company including its subsidiaries.

As of March 31,	**2015**	**2014**
Brazil		
Employees	-	3
Contractors	-	2
Bangladesh		
Employees	15	16
Contractors	-	2
Canada		
Employees	19	21
Contractors	1	2
Consultants	2	2
India		
Employees	61	69
Consultants	6	6
Indonesia		
Employees	26	44
Contractors	4	21
Madagascar		
Employees	-	3
Pakistan		
Contractors	1	1
Trinidad		
Employees	7	15

DIRECTORS AND OFFICERS

Directors

The following individuals are directors of Niko on the date hereof. The term of each director is from the date of the meeting at which he is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

Name and Residence	Positions Held With Niko	Biography[(1)]
E. Alan Knowles[(2)(4)(6)] Alberta, Canada	Director, Independent Director since September 2014	Mr. Knowles has eighteen (18) years of experience as an oil and gas analyst, most recently from 2000 to 2014 with Haywood Securities Inc. where he covered various senior, intermediate and international oil and gas companies. Prior to working as an analyst he worked in the oil and gas industry in various senior financial management positions, latterly as Vice President Finance and Chief Financial Officer of a junior Canadian producer.
Joshua A. Sigmon[(2)(3)(6)] New York, USA	Director, Independent Director since September 2014	Mr. Sigmon is a Director at Mount Kellett Capital Management LP and is part of the North American investment team. Prior to joining Mount Kellett, Mr. Sigmon was an Analyst at Coatue Management where he was responsible for generating long and short investment ideas and portfolio positions in a variety of sectors.
Kevin J. Clarke[(4)(5)(6)] New York, USA	Chairman of the Board Director since August 2014	Mr. Clarke is currently interim Chief Executive Officer of Niko Resources Ltd. Mr. Clarke was President and Chief Executive Officer of Catalyst Paper, from 2010 to 2013, and led the financial and operational restructuring of the company. Previously, Mr. Clarke was Group President and President of Worldcolor (Quebecor World) between 1986 to 2009.
Steven K. Gendal[(3)(5)(6)] New York, USA	Director, Independent Director since August 2014	Mr. Gendal has worked for over fourteen years at Whippoorwill Associates, Inc., an investment firm specializing in distressed debt and special situations, and is currently the co-portfolio manager.
Vivek Raj[(2)(3)(4)(5)(6)] Connecticut, USA	Director, Independent Director since September 2014	Mr. Raj is a Partner at CSL Capital Management LLC, where he manages a portfolio of companies under the energy and oilfield services sector. Mr. Raj was Vice President of Petrotiger from 2009 to 2010, where he worked on merger and acquisition deals, start-up of operations and operational improvements. From 2004 to 2007, Mr. Raj was an Engineer at Schlumberger Oil Field Services in China and Saudi Arabia.
William T. Hornaday[(4)(6)] Alberta, Canada	Director Director since August 2007	Mr. Hornaday is the Chief Operating Officer of Niko Resources Ltd. since 2005.

(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. Knowles is the Chairman and Mr. Sigmon and Mr. Raj are members of the Audit Committee.
(3) Mr. Sigmon is the Chairman and Mr. Gendal and Mr. Raj are members of the Compensation Committee.
(4) Mr. Hornaday is the Chairman and Mr. Knowles and Mr. Clarke are members of the Environmental & Reserve Committee.
(5) Mr. Gendal is the Chairman and Mr. Clarke and Mr. Raj are members of the Corporate Governance Committee.
(6) The Company does not have an executive committee.

Executive Officers

The following individuals are executive officers of Niko on the date hereof.

Name and Residence	Positions Held With Niko	Principal Occupation During Last Five Years
Kevin J. Clarke New York, USA	Interim Chief Executive Officer and Chairman of the Board	Mr. Clarke is currently interim Chief Executive Officer of Niko Resources Ltd. since October 2014. Mr. Clarke was the President and Chief Executive Officer of Catalyst Paper, from 2010 to 2013, and led the financial and operational restructuring of the company. Previously, Mr. Clarke was Group President and President of Worldcolor (Quebecor World) between 1986 to 2009.
William T. Hornaday Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Niko Resources Ltd. since 2005. Prior thereto, Vice President, Operations of Niko Resources Ltd.
Glen R. Valk Alberta, Canada	Chief Financial Officer, Vice President Finance and Corporate Secretary	Chief Financial Officer and Vice President Finance of Niko Resources Ltd. since January 2013. Prior thereto, Corporate Treasurer of Niko Resources Ltd. since August 2012. Prior thereto, VP Finance and Chief Financial Officer of a private oil and gas entity since December 2011. Prior thereto, Manager, Finance, Oil Sands / Arctic of ConocoPhillips Canada.
Robert D. McCrank Alberta, Canada	Chief Compliance Officer	Chief Compliance Officer of Niko Resources Ltd. since 2011 and prior to, a Barrister and Solicitor of McCrank Stewart Law Firm.

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 2,130,748 Common Shares constituting approximately two (2.27) percent of the issued and outstanding Common Shares.

Orders

To the knowledge of management of the Company, no director or executive officer is, as at the date hereof, or was within ten (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 thirty (30) consecutive days.

Bankruptcies

To the knowledge of management of the Company, two (2) of the directors of the Company, (a) is, as at the date hereof, or has been within the ten (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 ten (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. Mr. Clarke was Group President and President of Worldcolor (Quebecor World) in 1986 to 2009. Mr. Clarke was the President and Chief Executive Officer of Catalyst Paper in 2010 to 2013. Worldcolor (Quebecor World) filed CCAA in July 2008 and Catalyst Paper filed CCAA in January 2012. Mr. Gendal was a Director of LHI Liquidation Co. Inc (formerly Loehmann's Inc.), which filed CCAA in December 2013. The plan of liquidation was confirmed on July 22, 2014.

Penalties and Sanctions

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.

Majority Voting for Directors

The Board has adopted a policy (the "Majority Voting Policy") that will permit a Shareholder to vote for, or withhold from voting for, each director nominee separately. If a director nominee has more votes withheld than are voted in favor of him, such nominee will be expected to forthwith submit his resignation to the Board, effective on acceptance by the Board. The Board will refer the resignation to the Corporate Governance Committee of the Board (the "Corporate Governance Committee") for consideration. The Corporate Governance Committee will consider all factors deemed relevant by the members of the Corporate Governance Committee, including, without limitation, the stated reason or reasons why Shareholders who cast "withhold" votes for the director did so, the qualifications of the director, including, without limitation, the impact the director's resignation would have on the Company, and whether the director's resignation from the Board would be in the best interest of the Company and the Shareholders. Within ninety (90) days of receiving the final voting results, the Board will issue a press release announcing the resignation of the director or explaining the reasons justifying its decision not to accept the resignation. The Majority Voting Policy does not apply in circumstances involving contested director elections.

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 "C" to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of E. Alan Knowles, Joshua A. Sigmon and Vivek Raj as at March 31, 2015. E. Alan Knowles 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

E. Alan Knowles has eighteen (18) years of experience as an oil and gas analyst, most recently from 2000 to 2014 with Haywood Securities Inc. where he covered at various senior, intermediate and international oil and gas companies. In 2010 Mr. Knowles was awarded the Overall Top Stock Picker Award by Starmine Canada. Prior to working as an analyst he worked in the oil and gas industry for twenty (20) years in various senior financial management positions, latterly as Vice President Finance and Chief Financial Officer of a junior Canadian producer. Mr. Knowles earned a Bachelor of Commerce from the University of Calgary, and holds Chartered Financial Analyst (CFA) and Certified Management Accountant (CMA) designations. Mr. Knowles holds a Bachelor of Commerce from the University of Calgary.

Joshua A. Sigmon is a director at Mount Kellett Capital Management LP and is part of the North American investment team. Mount Kellett is a leading private equity firm based in New York with over $7 billion of capital under management of which $1 billion is invested or committed to investments in the energy sector. Prior to joining Mount Kellett, Mr. Sigmon was an Analyst at Coatue Management where he was responsible for generating long and short investment ideas and portfolio positions in a variety of sectors. Prior to Coatue, Mr. Sigmon worked at Cerberus Capital Management where he focused on private equity and distressed debt investments. Mr. Sigmon began his career as an investment banker in the Restructuring and Leveraged Finance Group at UBS. Mr. Sigmon has a Bachelor of Arts in International Economics and Business from Boston University and a Juris Doctorate/Master of Business Administration from University of Miami.

Vivek Raj is a partner at CSL Capital Management LLC, where he manages a portfolio of companies under the energy and oilfield services sector. Prior to that, Mr. Raj was Vice President of Petrotiger from 2009 to 2010, where he worked on merger and acquisition deals, start-up of operations and operational improvements. From 2004 to 2007, Mr. Raj was an engineer at Schlumberger Oil Field Services in China and Saudi Arabia. Mr. Raj holds a Master of Business Administration from Harvard Business School, and Bachelor of Technology from Indian Institute of Technology.

Audit Committee Oversight

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

Pre-Approval Policies and Procedures

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

Fees Paid to Auditors

The aggregate fees billed by the Company's external auditor for audit and professional services are as follows:

thousands (CAD$)	2015	2014
Audit Fees	737	896
Audit-related Fees	2	5
Tax Fees	3	30
Total	742	931

Audit fees were paid, or are payable, for professional services rendered by the auditors for the audit and quarterly reviews of the Company's consolidated financial statements, or services provided in connection with statutory and regulatory filings or engagements. Audit-related fees are related to professional services with respect to prospectuses, translation of foreign language financial statements and audit certifications. Tax fees are related to professional services including tax compliance, tax advice, tax planning and corporate tax filings.

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 June 24, 2015, the Company had issued and outstanding 94,019,172 Common Shares and no preferred shares. As at June 24, 2015, the Company had outstanding options to purchase 2,223,975 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.

Facilities Agreement

In December 2013, the Company entered into a definitive facilities agreement with certain institutional investors providing for senior secured Term Loan Facilities in an aggregate principal amount of $340 million. As of March 31, 2015, the outstanding principal on the facilities is $280 million, reflecting the Company's decision to forego its option to drawdown on the $20 million amount of Facility D, the repayment in June 2014 of the $20 million drawn on Facility E, and the prepayments of $20 million on Facility A in the fourth quarter of Fiscal 2015 resulting from the first amendment of the Term Loan Facilities agreed with the lenders. In the first quarter of Fiscal 2016, the Company and its lenders agreed to an extension and a second amendment to the facilities agreement, resulting in the prepayments of $30 million on Facility A and reducing the outstanding principal on the facilities to $250 million.

The key terms of the Facilities Agreement and related documentation are as follows:

Specific terms of facilities A/B/C:

- Facilities amount: $300 million (combined)
- Prepayment: At the Company's option at any time after December 20, 2015 (at a 7 percent premium, decreasing to 4 percent after December 20, 2016)
  At the lenders option (without premium) from the remaining net proceeds of certain asset sales, farm-outs, equity and debt issuances, after contract settlement payments and Facility D/E prepayments
- Repayment: On September 30, 2017
- Use of proceeds: $175 million Facility A: General corporate purposes, subject to certain restrictions
  $125 million Facilities B/C: Restricted to expenditures related to the D6 Block in India
- Interest: Quarterly cash interest payments at fifteen (15) percent per annum; commencing June 2014, potential additional five (5) percent per annum payable upon repayment ("D6 PIK interest") if first ranking security is not provided over the Company's participating interest in the D6 Block. The GOI has not yet approved the grant of security to the lenders. If security is provided prior to March 31, 2016, the D6 PIK interest to be paid will be reduced by fifty (50) percent and if the security is provided thereafter, the D6 PIK interest will be reduced by twenty-five (25) percent.

As per the second amendment to the Facilities Agreement agreed with the lenders in the first quarter of Fiscal 2016, the quarterly cash interest payment due in June 2015 has been deferred until September 2015.

Uncommitted D6 facility

The Facilities Agreement also includes a provision for an uncommitted facility that can be funded at the option of any the slenders if the Company is unable to fund the cash call requirements of the D6 Block. Advances under this facility are repayable from the Company's gross revenues from the D6 Block until an amount equal to two hundred (200) percent of the advanced amount has been paid.

Financial Covenants

In the original Facilities Agreement, the Company was subject to the following financial covenants:

- Maximum ratio of (a) consolidated senior debt (defined as debt incurred under facilities A, B and C and finance lease obligations) to (b) the consolidated EBITDAX (as defined in the facilities agreement) for the trailing four quarters, commencing with the period ending June 30, 2014.
- Minimum ratio of (a) proved plus probable reserves for the D6 Block to (b) senior debt, commencing with the period ending March 31, 2014.

As per the First and Second Amendments to the Facilities Agreement agreed with the lenders in the fourth quarter of Fiscal 2015 and the first quarter of Fiscal 2016, these financial covenants are waived until September 15, 2015.

General covenants

In the original facilities agreement, the Company agreed to several other undertakings and covenants, including:

- Maintenance of certain reserve accounts, including:
  - A reserve account for anticipated expenditures in the D6 Block, with a minimum balance that increased over time to the greater of $30 million and the Company's forecasted capital expenditures in the D6 Block for the subsequent six (6) month period.
  - A reserve account for settlement payments, with a minimum balance commencing December 31, 2014 equal to the payments required under the terms of the settlement agreement with Diamond Offshore for the subsequent six (6) month period.
  - A reserve account for debt service, with a minimum balance commencing December 31, 2014 equal to the interest payments due under the facilities agreement for the subsequent six (6) month period.

- Restrictions on cash expenditures relating to areas outside of India and Bangladesh, subject to certain exceptions.
- Requirement to raise certain minimum amounts from asset sales, farm-outs and/or equity issuances by June 30, 2015.
- Requirement that, subject to certain exceptions, asset sales be completed at fair market value with at least ninety (90) percent of the consideration received in the form of cash (including assumed liabilities).
- Restrictions on the incurrence of debt, granting of liens, investments and similar transactions.

In the First Amendment to the Facilities Agreement, the Company agreed to additional undertakings including:

- Requirement to achieve certain milestones related to the potential sale of the Company's interest in the D6 Block in India, which could include the sale of the Company.
- Requirement to maintain specified minimum cash balances.
- Restrictions on cash expenditures for non-core assets and general and administrative expenditures;

In the first amendment, the minimum balance requirement for the reserve accounts for settlement payments and debt service has been reduced to zero, and per the second amendment to the facilities agreement agreed with the lenders in the first quarter of Fiscal 2016, the minimum balance requirement for the reserve account for anticipated expenditures in the D6 Block was reduced to $20 million and the requirement to raise minimum amounts from asset sales, farm-outs and equity issuances has been waived until September 15, 2015. In addition, the Company is restricted from making any interest or other payments under the Convertible Notes, or under the terms of the agreement entered into the Diamond Settlement Agreement until September 30, 2015.

Since it appears unlikely the Company will be able to achieve the remaining milestones in the amended facilities agreement, the Company is pursuing an alternative strategic plan with the assistance of its advisors and stakeholders to enhance value over a longer period of time. The Company has been in discussions with its lenders about the structure of this plan and related further amendments to the facilities agreement.

Change in Control

If a change in control of the Company occurs or the Company's indirect subsidiary, Niko (NECO) Ltd., disposes of any part of its rights in respect of the D6 PSC, the Company shall make an offer to prepay all of the outstanding principal (plus a one (1) percent prepayment fee) and accrued and unpaid interest (including cash interest and D6 PIK interest) within ten (10) days of the change of control.

Deferred Obligation

As a condition of the Facilities Agreement, the Company entered into an agreement that provides for a monthly payment equal to six (6) percent of the Company's share of the gross revenues received from the D6 Block in India, commencing April 1, 2015 for a period of seven (7) years.

Security

The obligations under the Facilities Agreement and the deferred obligation are initially secured by:

- charges over all of the present and after-acquired personal and real property of the Company and certain of its subsidiaries;
- specific pledges and charges over the shares of substantially all of the Company's subsidiaries; and
- specific charges over the bank accounts of the Company and certain of its subsidiaries.

The Company has entered into security deeds to grant first ranking security with respect to Block 9 in Bangladesh which will become effective upon consent by Petrobangla and the Bangladesh government, and has agreed to use best endeavours to obtain all necessary India governmental authorizations to provide first ranking security over the Company's participating interest in the D6 PSC in India. Authorization has been received from the Reserve Bank of India and authorization from the GOI has been sought, but not yet granted.

Farm-in Options

As a condition of the Facilities Agreement, the Company entered into a farm-in rights agreement with an affiliate of the lenders that grants four (4) exclusive, irrevocable, non-assignable rights to acquire interests in pre-selected Indonesian PSCs. Each farm-in right provides the holder with the option to purchase a five (5) percent participating interest in selected PSCs (subject to a maximum acquired participating interest equal to the lesser of fifty (50) percent of the Company's aggregate participating interests in the selected PSC and ten (10) percent) by paying its proportionate share of the previously incurred costs of the selected PSC. A farm-in right may be exercised by the holder by giving at least seven (7) days' notice prior to the target spud date of a well to be drilled in the selected PSC. Unexercised farm-in rights expire on the earlier of (i) the date on which the eighth well on the selected PSCs is spudded and (ii) December 20, 2020.

Convertible Notes

In December 2012, the Company issued $115 million principal amount of Convertible Notes. The Convertible Notes were issued under the Indenture. The following summary of the terms of the Convertible Notes is qualified in its entirety by the terms of the Indenture. A complete copy of the Indenture is available on SEDAR at www.sedar.com.

The Convertible Notes bear interest at seven (7) percent per annum, which is payable semi-annually in arrears on June 30 and December 31 of each year to holders of record at the close of business on the preceding June 15 or December 15, respectively (or the first business day prior to such date if not a business day). The Convertible Notes mature on December 31, 2017, unless previously converted, redeemed or purchased. The principal amount of the Notes is payable at maturity in cash or, at the Company's option and subject to satisfaction of certain conditions, by delivery of freely tradable Common Shares, or a combination of cash and freely tradable Common Shares.

Ranking of Notes

The Convertible Notes are direct senior unsecured obligations of the Company and rank equally with one another and all other existing and future senior unsecured indebtedness of the Company. The Indenture does not restrict the Company or its subsidiaries from incurring additional indebtedness (whether senior and secured, pari passu or subordinated), disposing of assets, transferring assets among the Company and its subsidiaries or from mortgaging, pledging or charging its properties to secure any indebtedness or liabilities.

Ranking and Subordination of Guarantees

The Convertible Notes have been guaranteed, on a senior (except as described below) unsecured basis, by Niko Resources (Cayman) Ltd., Niko (NECO) Ltd. and Niko Exploration (Block 9) Ltd. (the "Guarantors"). 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 (as defined in the Indenture). The guarantees of the Convertible Notes are senior unsecured obligations of the Guarantors (subject to the Guarantee Subordination Terms described below). The guarantees of the Convertible Notes rank senior in right of payment to all existing and future subordinated indebtedness of the Guarantors. The guarantees of the Convertible Notes rank pari passu with all other senior unsecured indebtedness of the Guarantors, except for their guarantees of the Senior Secured Indebtedness. The guarantees of the Convertible Notes are also effectively subordinated to any existing and future secured indebtedness of the Guarantors to the extent of the assets securing such indebtedness.

Pursuant to the Guarantee Subordination Terms upon and during the continuance of any event of default under the Indenture, event of default under the Company's Credit Agreement or acceleration of the time for payment of any Senior Secured Indebtedness (as defined in the Indenture) which has not been rescinded: (i) all amounts payable by a Guarantor under its guarantee of the Convertible Notes will be subordinate and junior in right of payment to its guarantee of the Senior Secured Indebtedness; (ii) except for a demand for payment under such guarantee by the Trustee or the holders of the Convertible Notes, no enforcement steps or proceedings may be commenced in respect of such guarantee for a standstill period of ninety (90) days; and (iii) any payments received by the Trustee or the holders of the Convertible Notes under such guarantee in contravention of the foregoing conditions shall be held in trust for the benefit of the holder(s) of the Senior Secured Indebtedness and promptly paid over to such holders or their agent. The foregoing standstill period shall cease to apply if such Guarantor grants valid and enforceable and fully-perfected security over all or substantially all of its assets to secure its guarantee of the Senior Secured Indebtedness.

In addition, the Guarantee Subordination Terms provide that upon any distribution of the assets of a Guarantor on any dissolution, winding up, total liquidation or reorganization of such Guarantor (whether in bankruptcy, insolvency or receivership proceedings or upon an assignment for the benefit of creditors or any other marshalling of the assets and liabilities of such Guarantor, or otherwise): (i) all Senior Secured Indebtedness due and payable shall first be paid in full in cash, or provisions made for such payment, before any payment is made by such Guarantor under its guarantee of the Convertible Notes; and (ii) any payments received by the Trustee or the holders of the Notes under such guarantee in contravention of the foregoing condition shall be held in trust for the benefit of the holder(s) of the Senior Secured Indebtedness and promptly paid over to such holders or their agent.

Conversion Privilege

Holders may convert their Convertible Notes into freely tradable Common Shares at any time prior to the close of business on the earlier of: (i) the business day immediately preceding December 31, 2017; (ii) if called for redemption, on the business day immediately preceding the date specified by the Company for redemption of the Convertible Notes, or (iii) if called for to repurchase pursuant to a Change of Control (as defined below), on the business day immediately preceding the payment date, into approximately 88.4956 Common Shares for each $1,000 principal amount of Convertible Notes, representing a conversion price of $11.30 (the "Conversion Price"). The Conversion Price is subject to standard anti-dilution adjustments upon, inter alia, share consolidations, share splits, spin-off events, rights issues and reorganizations. The Conversion Price is also subject to customary adjustment for the payment of any dividends or distributions to common shareholders.

Optional Redemption
The Convertible Notes may not be redeemed by the Company prior to or on December 31, 2015. On and after January 1, 2016 and prior to or on December 31, 2017, the Company, may at its option redeem the Convertible Notes, in whole or in part, from time to time, at a price equal to one-hundred (100) percent of the principal amount being redeemed, plus any accrued and unpaid interest up to but excluding the date set for redemption, on not more than sixty (60) days and not less than forty (40) days prior notice, provided that the weighted average trading price of the Common Shares on the TSX for the twenty (20) consecutive days ending five (5) trading days prior to the date on which notice of redemption is provided (the "Current Market Price") is not less than one-hundred-thirty (130) percent of the Conversion Price.

Change of Control
Undertakings and covenants in respect of the convertible notes include:

- Requirement to make offers to purchase the Convertible Notes at par plus accrued and unpaid interest within thirty (30) days following a change of control (as defined below); and
- Requirement to obtain the consent of the holders of the Convertible Notes to sell all or substantially all of the Company's assets to another person, subject to certain exceptions.

For the purpose of such undertakings and covenants, subject to certain exceptions, a change of control includes a sale of all or substantially all of the Company's assets. A sale of assets of a subsidiary of the Company that would constitute all or substantially all of the assets of the Company on a consolidated basis is deemed to be a sale of all or substantially all of the assets of the Company.

Additionally, if a Change of Control occurs in which ten (10) percent or more of the consideration for the Common Shares in the transaction or transactions constituting a Change of Control consists of: (a) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenter's appraisal rights); (b) trust units, limited partnership units or other participating securities of a trust, limited partnership or similar entity; (c) equity securities that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (d) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then, subject to regulatory approvals and the Change of Control becoming effective, during the period beginning ten (10) trading days before the anticipated date on which the Change of Control becomes effective and ending thirty (30) days after the Change of Control purchase offer is delivered, holders of Convertible Notes may elect to convert their Convertible Notes at the Change of Control Conversion Price (as defined in the Indenture) and, subject to certain limitations and stock exchange requirements, receive, instead of the number of Common Shares they would otherwise be entitled to receive, a number of Common Shares per $1,000 principal amount of Convertible Notes determined in accordance with the Change of Control Conversion Price as set forth in the Indenture.

Under the Indenture, a "Change of Control" of the Company is deemed to have occurred upon the acquisition by any person, or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104), of: (i) voting control or direction of an aggregate of fifty (50) percent or more of the outstanding Common Shares; or (ii) all or substantially all of the assets of the Company, but shall not include a sale, merger, reorganization, arrangement, combination or other similar transaction if the previous holders of Common Shares hold at least fifty (50) percent of the voting control or direction in such merged, reorganized, arranged, combined or other continuing entity (and in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets) immediately following the completion of such transaction.

Method of Payment
Subject to required regulatory approval and provided that there is not a current Event of Default (as defined in the Indenture), 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, upon not less than forty (40) days and not more than sixty (60) days prior notice, by issuing and delivering that number of freely tradable Common Shares obtained by dividing the principal amount of the Convertible Notes by ninety-five (95) percent of the Current Market Price on the date of redemption or maturity, as applicable.

Subject to required regulatory approval and provided that there is not a current Event of Default (as defined in the Indenture), the Company may elect, from time to time, to satisfy its obligation to pay interest on the Convertible Notes, on the date it is payable under the Indenture (i) in cash; (ii) by delivering Common Shares to the Trustee for sale, to satisfy the interest obligations in accordance with the Indenture, in which event holders of the Convertible Notes will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares; or (iii) any combination of (i) and (ii) above.

Purchase for Cancellation

The Company may, to the extent permitted by applicable law, at any time purchase the Convertible Notes in the open market or by tender at any price or by private agreement. Any Convertible Note purchased by the Company will be surrendered to the Trustee for cancellation. Any Convertible Notes surrendered to the Trustee may not be reissued or resold and will be cancelled promptly.

Events of Default

The Indenture provides that an event of default ("Event of Default") in respect of the Convertible Notes will occur if any one or more of the following described events has occurred and is continuing with respect of the Convertible Notes: (a) failure for thirty (30) days to pay interest on the Convertible Notes when due; (b) failure to pay principal (whether by way of payment of cash or delivery of Common Shares) on the Convertible Notes when due, whether at maturity, upon redemption, following a Change of Control, by declaration or otherwise; (c) default in the delivery, when due, of any Common Shares or other consideration payable upon conversion with respect to the Convertible Notes, which default continues for fifteen (15) days; (d) default in the observance or performance of any other covenant or condition of the Indenture and the failure to cure (or obtain a waiver for) such default for a period of thirty (30) days after notice in writing has been given by the Trustee or from holders of not less than twenty-five (25) percent in aggregate principal amount of the Convertible Notes to the Company specifying such default and requiring the Company to rectify or obtain a waiver for same; (e) certain events of bankruptcy, insolvency or reorganization of the Company or any material subsidiary under bankruptcy or insolvency laws; or (f) if an event of default occurs or exists under any indenture, agreement or other instrument evidencing or governing indebtedness for borrowed money of the Company or any Guarantor, if that default (i) is caused by a failure to pay obligations thereunder prior to the expiration of any applicable grace or cure period, or (ii) results in the holders thereof having the right to accelerate such obligations prior to their stated maturity and, in each case, the principal amount of all such obligations aggregates an amount greater than $25,000,000 (or the equivalent amount in another currency); and such default referred to in clause (f) above is not cured or waived within a period of forty-five (45) days from the occurrence thereof.

If an Event of Default has occurred and is continuing, the Trustee may, in its discretion, and shall upon request of holders of not less than twenty-five (25) percent of the principal amount of Convertible Notes then outstanding, declare the principal of and interest on all outstanding Convertible Notes to be immediately due and payable. In the case of certain events of bankruptcy or insolvency, the principal amount of the Convertible Notes, together with any accrued and unpaid interest through the occurrence of such event, shall automatically become due and payable. In certain cases, the holders of more than fifty (50) percent of the principal amount of the Convertible Notes then outstanding may, on behalf of the holders of all Convertible Notes, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Per the Second Amendment to the Facilities Agreement, the Company will seek (i) the consent of the holders of the Convertible Notes to defer to September 30, 2015 the interest payment due on June 30, 2015. To date, consent has not been obtained from the holders of the Convertible Notes and it appears unlikely that consent will be obtained prior to June 30, 2015. As a result, it is probable that the Company will be in breach of the indenture governing the Convertible Notes. Under the terms of the indenture governing the Convertible Notes, an event of default would not occur until July 30, 2015.

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 2015	0.63	0.33	6,613,746
February 2015	0.76	0.23	26,016,606
January 2015	0.28	0.22	4,340,857
December 2014	0.39	0.23	11,027,564
November 2014	0.33	0.25	6,848,092
October 2014	1.07	0.26	27,561,596
September 2014	1.65	0.60	13,057,832
August 2014	2.03	1.40	3,747,265
July 2014	2.29	1.86	3,815,241
June 2014	2.94	1.96	7,731,893
May 2014	2.60	1.94	7,358,838
April 2014	2.39	1.92	4,046,859

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 2015	20.03	20.03	319,000
February 2015	30.76	36.99	746,000
January 2015	13.00	13.01	323,000
December 2014	12.55	13.00	1,539,000
November 2014	18.99	18.99	1,486,000
October 2014	28.00	29.00	3,041,000
September 2014	47.50	47.50	1,359,000
August 2014	48.51	50.00	140,000
July 2014	53.90	53.90	7,336,800
June 2014	57.51	57.51	1,144,000
May 2014	57.01	57.01	1,885,000
April 2014	53.94	53.95	79,000

(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 not been adjusted from the TSX reported volumes to reflect the original denomination.

PRIOR SALES

Other than: (i) the issuance of options to acquire an aggregate of 579,071 Common Shares at exercise prices ranging from Cdn$2.03 to Cdn$2.29 and having a weighted average exercise price of Cdn$2.22 per Common Share; (ii) the issuance of 3,306,234 Common Shares pursuant to the conversion of Unsecured Notes, the Company has not issued any Common Shares or securities convertible or exchangeable into Common Shares during the past twelve (12) month period.

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, 2011 and 2014. 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 2017.

The following is a summary description of the general operation of the amended and restated shareholder rights plan agreement dated September 11, 2011 as amended by the Shareholder Rights Plan Amendment Agreement dated September 11, 2014 (the "Rights Plan"). This summary is qualified in its entirety by reference to the text of the 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 Rights Plan.

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

<u>Term</u>: The Rights Plan 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 percent or more of the Common Shares, other than by an acquisition pursuant to a take-over bid permitted by the Rights Plan (a "Permitted Bid"). The acquisition by any person (an "Acquiring Person") of 20 percent 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.

<u>Certificates and Transferability</u>: 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.

<u>Permitted Bid Requirements</u>: 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 forty-five (45) days and Common Shares tendered pursuant to the take-over bid may not be taken up prior to the expiry of the forty-five (45) day period and only if at such time more than fifty (50) percent of the Common Shares held by Independent Shareholders have been tendered to the take-over bid and not withdrawn; and

4. if more than fifty (50) percent of the Common Shares held by Independent Shareholders are tendered to the take-over bid within the forty-five (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 ten (10) business days from the date of such public announcement.

The 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 thirty-five (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 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 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 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 twenty (20) percent 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 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.

MATERIAL CONTRACTS

The following is a list of the material contracts that the Company has entered into within the last financial year or before the last financial year which remain in effect:

- Facilities Agreement as described under "Description of Capital Structure";
- D6 Royalty Agreement as described under " Development of the Business - History";
- Indenture relating to the Convertible Notes as described under "Description of Capital Structure";
- Rights Plan as described under "Shareholder Rights Plan";
- First Amendment to Facilities Agreement as described under "Description of Capital Structure";
- Extension under Facilities Agreement as described under “Description of Capital Structure”;
- Second Amendment to Facilities Agreement as described under "Description of Capital Structure";

Additional details regarding the First Amendment to Facilities Agreement are contained in the material change report of the Company dated February 12, 2015 as filed on SEDAR at www.sedar.com.

Additional details regarding the Extension under Facilities Agreement are contained in the material change report of the Company dated May 1, 2015 as filed on SEDAR at www.sedar.com.

Additional details regarding the Second Amendment to the Facilities Agreement are contained in the material change report of the Company dated June 1, 2015 as filed on SEDAR at www.sedar.com.

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

Going Concern

Due primarily to the projected impact of the new domestic gas pricing policy for India on the Company's future liquidity and significant uncertainty on the future long-term price outlook in India, in December 2014, the Company engaged Jefferies LLC as its financial advisor to assist the Company in pursuing strategic alternatives including the sale of assets of the Company, a merger or other business combination, the outright sale of the Company, a refinancing of its existing debt with replacement debt, or some combination thereof.

The Company's operating results for the trailing four quarters ended December 31, 2014 were not sufficient to satisfy the senior debt to EBITDAX financial covenant and under the original Facilities Agreement; a breach of this covenant would have resulted in the right for the lenders to accelerate payment of the outstanding principal amount of the Term Loan Facilities of $308 million. Due to cross default provisions of the note indenture for the Company's seven (7) percent senior unsecured convertible notes due December 31, 2017, an event of default under the Facilities Agreement that was not cured within forty-five (45) days would have permitted the holders of the Convertible Notes to accelerate payment of the outstanding principal amount of the Convertible Notes.

In February 2015, the Company and its lenders agreed to amend the terms of the facilities agreement in order to ensure that an event of default did not occur. It was believed that the amendment would provide the Company with sufficient time to pursue the potential sale of the Company's interest in the D6 Block in India or the sale of the Company. As the process for the sale of the Company's interest in the D6 Block or the Company did not achieve certain milestones agreed to with the lenders in the first amendment, in May 2014, the Company and its lenders entered into two agreements which, subject to certain conditions, resulted in extensions of milestones to complete the sales process and further extended the waiver of certain financial covenants and undertakings set out in the facilities agreement until September 15, 2015.

As per the amendments to the Facilities Agreement, the Company is restricted to specified amounts of capital expenditures for non-core assets and general and administrative expenditures during calendar 2015, and must maintain specified minimum total cash balances. In addition, the Company is restricted from making any interest or other payments under the Convertible Notes, or under the terms of the Diamond Settlement Agreement until September 30, 2015.

The Company has therefore initiated discussions and negotiations with holders of Convertible Notes and representatives thereof to seek their consent to defer to September 30, 2015 the interest payment due on June 30, 2015. In addition, the Company has sought the consent of the parties to the Diamond Settlement Agreement to defer any payments that are due and payable prior to September 30, 2015 and eliminate the required minimum balance in a reserve account specified in the Diamond Settlement Agreement. To date, no consents have been obtained from the holders of the Convertible Notes or the parties to the Diamond Settlement Agreement (collectively, the "Consents"), and it appears unlikely that Consents will be obtained prior to June 30, 2015. As a result, it is probable that the Company will be in breach of the indenture governing the Convertible Notes and the Diamond Settlement Agreement. Under the terms of the indenture governing the Convertible Notes, an event of default would not occur until July 30, 2015. Under the Diamond Settlement Agreement, in the event of a breach, the parties thereto may seek to enforce their unsecured rights, but the extent of any damages they may suffer from a breach and the strength of any claim they could make is not clear at this time.

Since it now appears unlikely that the Company will be able to achieve the remaining milestones in the amended facilities agreement and that the Company will default under key unsecured obligations, the Company is pursuing an alternative strategic plan with the assistance of its advisors to enhance value over a longer period of time. The Company has been in discussions with its lenders about the structure of this plan and plans to have further discussions with other key stakeholders, including the holders of the Convertible Notes and the parties to the Diamond Settlement Agreement. This alternative plan would likely be subject to certain approvals by various stakeholders and could have a negative impact on stakeholders and the value of their interests in the Company. No assurance can be made that any strategic plan can be accomplished at all or on a timely basis. The failure to effect a transaction pursuant to a strategic plan on a timely basis could prove to be unsatisfactory for security holders, which would likely have a material adverse impact on the value of their interest in the Company.

The Company has the following sources of funding for its planned operating, investing and financing cash outflows (including working capital requirements):

- Unrestricted cash and cash equivalents as at March 31, 2015 of $60 million;
- Restricted cash as at March 31, 2015 of $38 million (subject to terms of the facilities agreement, as amended);
- Receipts of oil and natural gas revenues from its producing assets in India and Bangladesh;
- Potential proceeds from asset sales, farm-outs and other arrangements; and
- Potential proceeds from future equity or debt issuances.

The Company believes that it has sufficient liquidity for the foreseeable future to satisfy the anticipated cash requirements of its operating subsidiaries in India and Bangladesh and its corporate general and administrative expenses. In the alternative strategic plan that the Company is pursuing with its stakeholders, the Company is negotiating to reduce future cash outflows related to its Facilities Agreement, Convertible Notes and Diamond Settlement Agreement until such time that the value of the Company's assets can be enhanced or alternative arrangements are agreed to.

As at March 31, 2015, the Company had $102 million of accounts payable and accrued liabilities related to its exploration subsidiaries in Indonesia and Trinidad and $273 million of exploration work commitments associated with these subsidiaries, including commitments of the Trinidad subsidiaries that are backed by parent company guarantees.

The terms of the Company's Term Loan Facilities limit the funding of capital expenditures and working capital requirements of the Company's exploration subsidiaries and the Company is evaluating its options for these subsidiaries as part of its strategic plan. There is significant uncertainty regarding whether these efforts will be sufficient to allow certain of the Company's exploration subsidiaries to meet existing and future obligations and continue activities in the future.

As a result of the foregoing matters (including the ongoing obligations of the Company and its subsidiaries), there is material uncertainty that may cast significant doubt about the ability of the Company to continue as a going concern.

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.

Ability to Make Payment

The ability of Niko to make scheduled payments on or refinance its debt obligations depends on Niko's financial condition and operating performance, which are subject to a number of factors beyond Niko's control. Niko may be unable to maintain a level of cash flows from operating activities sufficient to permit Niko to pay the principal and interest on its indebtedness, including the Facilities Agreement and Convertible Notes. To the extent that Niko does not complete anticipated farm-outs, asset sales or other arrangements, it may require addition financing or may not have sufficient funds to meet contractual obligations under the PSCs. If Niko's cash flows and capital resources are insufficient to fund its debt service obligations, Niko could face substantial liquidity problems and could be forced to reduce or delay investments and capital expenditures or to dispose of material assets or operations, seek additional debt or equity capital or restructure or refinance its indebtedness. Niko may not be able to effect any such alternative measures on commercially reasonable terms or at all and, even if successful, those alternative actions may not allow Niko to meet its scheduled debt service obligations. There can be no assurance that debt or equity financings or cash generated by operations will be sufficient or available to meet obligations for debt repayments, work commitments, development, production and acquisition of oil and natural gas reserves in the future.

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. For six PSCs in Indonesia that had commitments due in November 2014 and one PSC that had commitments due in May 2015, the Company requested amendments to the PSCs to extend the initial exploration period to ten years and extend the deadlines for the commitments. Extensions have not been granted and as at March 31, 2015, certain of the Company's subsidiaries have recognized liabilities of $117 million for these unfulfilled exploration work commitments. In addition, liabilities of $75 million have been recognized as at March 31, 2015 for unfulfilled exploration work commitments in certain PSCs in Trinidad as extensions to the deadlines for the commitments have not been received.

Covenants and Conditions under its Existing Loan Agreement

The Company is required to comply with covenants and conditions under its existing loan agreements and amended agreements, including the Facilities Agreement, Convertible Notes and Diamond Settlement Agreement. In the event that the Company does not comply with the covenants and conditions, repayment could be required by the lenders. Accordingly, failure to comply with the covenants under its facilities could have a materially adverse effect on the Company and its financial condition. There is no assurance that the Company will obtain the consents required under the Second Amendment to the Facilities Agreement. It is probable that the Company will be in breach of the indenture governing the Convertible Notes and the Diamond Settlement Agreement. Under the terms of the indenture governing the Convertible Notes, an event of default would not occur until July 30, 2015. Under the Diamond Settlement Agreement, in the event of a breach, the parties thereto may seek to enforce their unsecured rights, but the extent of any damages they may suffer from a breach and the strength of any claim they could make is not clear at this time.

Termination of PSCs due to Insolvency

Niko's PSCs relating to the D6 Block and NEC-25 contain provisions that permit the GOI 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 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. Recent case law in India has also confirmed that the GOI could selectively terminate the rights of a defaulting PSC participant provided that the remaining PSC participants have the opportunity to exercise their rights under the PSC. This could have a material adverse effect on the rights of creditors in the event of the Company's bankruptcy or a filing pursuant to the Companies' Creditors Arrangement Act (Canada).

The GOI 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 GOI, 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 GOI, 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 GOI will not exercise its rights of termination if the defaulting party cures the default within the applicable cure period or 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.

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 operating 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 write downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices or may elect to defer capital expenditures during periods of low commodity prices or commodity price uncertainty. 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.

Termination of Rights under Joint Operating Agreements

Under its joint operating agreements, a default arises if Niko's subsidiary fails to pay its financial obligations when due and, if such financial default continues for more than a specified period of time, generally 60 to 90 days, there is a forfeiture option that is exercisable by the other parties to the joint operating agreement. The exercise of this forfeiture right in respect of Niko's interests in the D6 Block, if enforceable, would have a material adverse effect on the business, financial condition, results of operations and prospects of the Company.

Most of the joint operating agreements to which Niko's subsidiaries are a party also contain provisions which may facilitate the removal of the Niko subsidiary as operator if it becomes insolvent.

Performance Guarantees

For its PSCs in India and Pakistan, the Company has provided performance guarantees from the parent to the respective governments guaranteeing the performance of the Company's subsidiaries' obligations under the PSCs. For its PSCs in Trinidad and Tobago and Brazil, the Company has provided financial guarantees to the respective governments. Under these financial guarantees, the recipients of the guarantees have the right to collect on the guarantees if the Company's subsidiaries do not carry out the minimum work commitments required under the PSCs. Certain subsidiaries of the Company that own interests in PSCs in Indonesia have provided performance security guarantees to the GRI and the subsidiary is required to provide funds to support the guarantees. Under these performance security guarantees, the recipients of the guarantees have the right to collect on the guarantees if the subsidiaries do not carry out specified work commitments required under the PSCs. Refer to "Licensing and Regulatory Requirements" risk section for additional information.

Dependence on Key Customers

The Company sells all of its production in Bangladesh to Petrobangla. Such sales comprised thirty-eight (38) percent of the Company's total revenues for Fiscal 2015, compared to thirty-six (36) percent for Fiscal 2014. If The Company 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 ("Money Suit") that was filed in Bangladesh by Petrobangla and the Republic of Bangladesh demanding approximately $105 million in compensation (based on an exchange rate of Bangladeshi taka to US dollar of 76.26 to 1.00 as of March 31, 2015). The legal process under the Money Suit could take up to ten (10) years to settle. Various hearings have taken place and the legal process is moving slowly. There is a risk that Niko will lose the lawsuit in the Bangladesh law courts. Any negative result to the Company 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 initiated two arbitrations with the 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 these claims and the timing of any such resolution are uncertain. Any negative result to the Company 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 the Company 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 or operations, 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

The Company's current operations are, and future operations will be, dependent upon the grant and maintenance of appropriate licenses, concessions, leases, 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 authorizations will be granted, renewed, renewable, extended, or may be withdrawn, or made subject to limitations or onerous conditions. Many of the Company’s projects are subject to minimum work commitments within the respective PSCs (see “Assets” description for each country). 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. To the extent that such future approvals are required and not obtained, the Company may be prohibited from proceeding with planned exploration or development of its properties, or could potentially lose concessions due to not being able to fulfil requirements.

The Company 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 the Company 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 The Company. As a result of the guilty plea, the Company paid a CAD$9.5 million fine and was sentenced to a three (3) year term of probation. The order setting the terms of probation (the "Order"), imposed a number of requirements including that the Company 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 submit a yearly report, drafted by an independent auditor, reviewing The Company's anti-corruption and compliance programs. All of the reports were completed and submitted in accordance with the Order. The term of probation expired on June 23, 2014. The public authorities charged by the Order with reviewing the Company’s compliance with the requirements of the Order have completed their review. They have determined that the Company has adhered to the terms of the Order and has not breached its plea agreement. No further proceedings have been taken against 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 the Company'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 above, the Company pled guilty in 2011 to a violation of the CFPOA statute for conduct that took place in Bangladesh in 2005. 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, the Company has not conducted a comprehensive review of its historical activities in all jurisdictions in which it operates. he 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 the Company'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, the Company, 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, the Company'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.

Fluctuating Prices

In October 2014, the Cabinet Committee of Economic Affairs of the GOI approved of the New Domestic Natural Gas Guidelines for domestic gas sales in India. Gas prices are to be determined on a semi-annual basis. Prices will be calculated based on a volume weighted average of prices in the US, Canada, Europe and Russia based on the twelve (12) month trailing average price with a lag of three (3) months with deductions for transportation and treatment charges. 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.

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 the Company 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 the Company's future rate of growth.

Refer to “Legal Proceedings and Regulatory Action” for D6 gas pricing arbitration.

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.

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 The Company 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 US Dollars. As a result, the Company has limited its cash exposure to fluctuations in the value of the US Dollar versus other currencies. However, the Company is exposed to fluctuations in the value of the Indian Rupee, Bangladeshi Taka, Trinidad and Tobago Dollar, Indonesian Rupiah, and Pakistani Rupee against the US Dollar on working capital of the Company's foreign subsidiaries. Corporate operations in Canada include Canadian Dollar denominated accounts receivable, accounts payable and accrued liabilities and Convertible Notes, which are exposed to fluctuations against the US Dollar. The Company reports the consolidated financial statements in US Dollars. For Fiscal 2015, the Company had a foreign exchange gain of $12 million versus a foreign exchange loss of $6 million for Fiscal 2014.

Delivery Commitments

In accordance with natural gas sales contracts to customers of production from the Hazira field in India, the Company had committed to deliver certain minimum quantities and was unable to deliver the minimum quantities for the period ended December 31, 2007. The Company's partner in the Hazira field delivered the shortfall volumes in return for either: (a) delivery of replacement volumes five times greater than the shortfall; (b) a cash payment; or (c) a combination of (a) and (b). The Company's partner has served a notice of arbitration as the Company is unable to supply gas from the D6 Block to the partner and the arbitration process has commenced. The Company 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.

Simultaneously, the Company's partner has also filed an alternate claim under arbitration for the above shortfall volumes should their original claim be rejected by the arbitration panel. Under the alternate claim, the joint operating partner is claiming compensation for the actual gas procured at market prices to meet the shortfall of gas supplied to the customers under the gas sales contract.

The arbitration for both claims is in process and the matter is sub judice. The Company believes that the outcome is not determinable.

The Company may not be able to supply gas to a customer in Hazira whose contract runs until April 2016. The Company has notified the customer that the underperformance of reservoir is a force majeure event. The customer does not agree with this position and has served a notice of arbitration on the Company. The arbitration is in process. The Company believes that it has a very strong legal case, however the outcome is not determinable. See "Legal Proceedings and Regulatory Actions - Proceedings in India - Hazira Field".

Cost Recovery Dispute related to D6 PSC

In a May 2012 letter, the GOI alleged that the D6 contractor group is 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 further asserted that certain joint operation costs are therefore disallowed for cost recovery. The contractor group is of the view that the disallowance of recovery of costs incurred by the joint operation has no basis in the terms of the PSC and that there are strong grounds to challenge the action of the GOI. The contractor group has commenced arbitration proceedings against the GOI challenging the allegations and the disallowance of cost recovery. In a July 2014 letter, the GOI updated their preliminary estimate of disallowed costs as at March 31, 2014 to $2.4 billion. To the extent that any amount of joint operation costs are disallowed, such amount would be removed from the calculation of profit petroleum, a portion of which would be payable to the GOI under the PSC. Because profit petroleum percentages for the contractor group and the GOI change as the contractor group recovers specified percentages of their investments, the potential impact on the GOI's share of profit petroleum is dependent on the future revenue and expenditures in the block and cannot be precisely determined. Based on the current profit petroleum percentage of ninety (90) percent for the contractor group and 10 percent for the GOI, if the GOI were to be successful in the cost recovery arbitration and the entire $2.4 billion ($238 million Niko share) of costs were disallowed, Niko's share of the potential impact would be a total of $24 million, of which $12 million would relate to periods up to March 31, 2015 and $12 million would relate to future periods. The GOI has also raised issues regarding other potential adjustments to the profit petroleum calculation and the contractor group has refuted these potential adjustments. See "Legal Proceedings and Regulatory Actions - Proceedings in India – D6 Block".

Taxation Risks

a) *Hazira and D6*

The Company is claiming a tax holiday under Income Tax Act ("Act") that provides for a tax holiday deduction for eligible undertakings related to the Hazira and Surat fields. However the tax department contends that the Company is not eligible for the requested tax holiday because: a) the holiday only applies to "mineral oil" which excludes natural gas; and / or b) the Company has inappropriately defined undertakings. With respect to undertakings eligible for the tax holiday deduction, the Act was retrospectively amended to include an "explanation" on how to determine undertakings. The Act now states that all blocks licensed under a single contract shall be treated as a single undertaking.

On March 26 2015, the High Court of Gujarat in India issued a favorable judgment on the retrospective application of the definition of undertakings and whether or not mineral oil includes natural gas for the purposes of the income tax holiday claims for the Company's fields in India. The judgment states that the GOI's retrospective application of the definition of undertakings as "all blocks licensed under a single contract shall be treated as a single undertaking" is unconstitutional and has been struck down. As such, the Company's position that an undertaking can be defined as a well or cluster of wells has been upheld for the purposes of the tax holiday provisions in the Act in India. The judgment also states that the term "mineral oil" for the purposes of the tax holiday provisions in the Act in India takes within its purview both petroleum products and natural gas.

If the tax department appeals the High Court ruling in the Supreme Court and should the Supreme Court overturn the ruling of the High Court, the Company would have to accordingly change its tax position and pay additional taxes of $32 million. In addition, the Company could be obligated to pay interest on taxes for the past periods.

The Company is facing a similar unfavorable tax assessment for the taxation year 2012 relating to tax holiday claimed by the Company's subsidiary that owns its interest in the D6 Block.

There is a risk of penalties and interest on amounts assessed and the assessed amounts, the penalties and the interest may have a significant adverse effect on the Company and its financial condition.

b) Indonesia

The Tax Directorate General of Indonesia had assessed several oil and gas companies operating in LBT. Certain of the Company's Indonesian subsidiaries holding interests in three (3) of its operated offshore PSCs (Obi, South East Seram and Aru) received assessment notices raising demands for a total of $31 million net for assessment years 2012 to 2014. The operator for two (2) of the Company's partner-operated offshore PSCs (North Ganal and Halmahera II) has also received 2012 to 2014 assessments totaling $5 million net. In all cases objection letters and appeals have been filed regarding these assessments.

In the event that the appeal is not successful, the subsidiaries of the Company could be liable for a penalty of up to one-hundred (100) percent of the LBT tax owing in addition to the amount of assessed tax, for a potential liability of $61 million.

There is a risk of penalties and interest on amounts assessed and the assessed amounts, the penalties and the interest may have a significant adverse effect on the Company and its financial condition. Refer to "Legal Proceedings and Regulatory Actions - Proceedings in Indonesia".

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.

Risks Relating to Reserves

No Ownership in Oil and Natural Gas Reserves

Pursuant to the laws of India, Bangladesh, Indonesia, Trinidad and Tobago, and Brazil, 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 The Company, from exploiting these crude oil and natural gas reserves, or interfere in the sale or transfer of the production, the Company'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. The Company may not be able to find reserves at a reasonable cost, develop reserves within required time-frames or at a reasonable cost, or sell these reserves for a reasonable profit. Reserves may be revised, deferred or be subject to material reductions due to economic and technical factors. 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;
- assumptions made for pricing inputs going into the Indian domestic natural gas guidelines;
- assumptions concerning future operating costs; development costs, workover costs and decommissioning obligations and;
- assumptions regarding various taxes including excise duty, service tax, sales tax, minimum alternate tax and income tax.

Future natural gas prices used in the Deloitte Report are based on prices currently in place and estimated gas prices based on the new pricing formula, in respect of the D6 Block for periods after March 31, 2015, future natural gas prices reflect the Company's anticipated contractual prices upon redetermination. Future crude oil and NGL prices reflect 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. Deloitte has applied a price deck on India gas reserves as at March 31, 2015 based on Pricing Formula disclosed under “Assets – India” including various assumptions that are discussed in the “Disclosure of Reserves” section.

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 / Operations

The Company's proposed development opportunities are conducted as joint ventures or joint operations where it is 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 Arrangements

The Company carries out a portion of its business through joint operations 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.

The Company is a joint operating partner in most of its fields and blocks. As a result, the Company's ability to execute its business plan may be constrained by partner involvement and the action of its joint operating partners particularly where the joint operating 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 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. The Company's competitors include oil and gas companies which many have greater technical and financial resources, staff and facilities than those of the Company. Some of those competitors 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. 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

ICSID Arbitration

The Company’s indirect subsidiary, NRBL, is a party to two arbitration disputes to be decided upon by a tribunal panel (“Tribunal”) under the ICSID. These disputes are related to its Feni Gas Purchase and Sales Agreement (“GPSA”) with Bangladesh Oil, Gas and Mineral Corporation (“Petrobangla”) and to its joint venture agreement (“JVA”) with Bangladesh Petroleum Exploration & Production Company Limited (“BAPEX”) for the Feni and Chattak fields in Bangladesh:

1. “Payment Claim”: Dispute over payment for gas delivered from the Feni field from and after November 2, 2004 under the Feni GPSA with Petrobangla.
2. “Compensation Declaration”: Dispute over compensation claims arising from the uncontrolled flow problems that occurred in Chattak field in January and June 2005, including the claims raised in the pleadings filed in the Money Suit discussed below.

In August 2013, the ICSID Tribunal delivered its decision that ICSID does have jurisdiction over the two arbitration disputes.

In September 2014, the Tribunal issued a favorable decision on the Payment Claim dispute. The Tribunal decided that:

i. Petrobangla owes NRBL $25 million plus Bangladeshi taka (“BDT”) 140 million ($2 million) for gas delivered from November 2004 to April 2010;
ii. Petrobangla must pay interest on NRBL’s invoices at the rate of six month London Interbank Offered Rate plus 2 percent on the US$ amounts and at 5 percent for the BDT amounts, with interest due from 45 after the delivery date of each invoice till the funds are placed at NRBL’s unrestricted disposition; and
iii. The parties were invited to seek an amicable settlement with respect to the implementation of the present decision and to report to the Tribunal by no later than September 30, 2014. Failing amicable settlement, either party may ask the Tribunal to order provisional measures or issue a final decision concerning the outstanding amounts.

The Payment Claim amount due to NRBL totals $34 million (including $7 million for accrued interest up to the awarded date). An amicable settlement has not been reached between the parties and the Company has requested that the Tribunal issue a final decision concerning the outstanding amounts. The Company believes that while the magnitude of the Payment Claim amount is determinable, the process and timing for implementation is not yet certain.

At the direction of the Tribunal, the hearing on the Compensation Declaration originally scheduled for November 2014 has been rescheduled for November 2015.

Money Suit

During the year ended March 31, 2006, NRBL received a letter from Petrobangla demanding compensation related to the uncontrolled flow problems that occurred in the Chattak field in January and June 2005. In June 2008, NRBL was named as a defendant in a lawsuit (the “Money Suit”) that was filed in Bangladesh by the GOB and Petrobangla, demanding compensation as follows:

i. $5 million for 3 Bcf of free natural gas delivered from the Feni field as compensation for the burnt natural gas;
ii. $10 million for 5.89 Bcf of free natural gas delivered from the Feni field as compensation for the subsurface loss;
iii. Bangladesh Taka 846 million ($11 million) for environmental damages, an amount subject to be increased upon further assessment;
iv. Bank guarantee for $79 million for 45 Bcf of natural gas as compensation for further subsurface loss to be finally determined on the basis of production data and analysis; and
v. any other claims that arise from time to time.

Various court dates for the Money Suit have been set for which the proceedings have been progressing at a slow pace. If NRBL were to lose the Money Suit, the Company may lose its rights to the assets of NRBL (including the receivable for gas sales supplied under the GPSA). The Company believes that the outcome of the Money Suit and the associated cost to the Company, if any, are not determinable. As such, no amounts have been recorded in these consolidated financial statements. Settlement costs, if any, will be recorded in the period of determination.

Proceedings in India

Hazira Field

In accordance with natural gas sales contracts to customers of production from the Hazira field in India, the Company had committed to deliver certain minimum quantities and was unable to deliver the minimum quantities for a period ended December 31, 2007. The Company's partner in the Hazira field delivered the shortfall volumes in return for either: (a) delivery of replacement volumes five times greater than the shortfall; (b) a cash payment; or (c) a combination of (a) and (b). The Company's partner has served a notice of arbitration as the Company is unable to supply gas from the D6 Block to the partner and the arbitration process has commenced. The Company 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.

Simultaneously, the Company's partner has also filed an alternate claim under arbitration for the above shortfall volumes should their original claim be rejected by the arbitration panel. Under the alternate claim, the joint operating partner is claiming compensation for the actual gas procured at market prices to meet the shortfall of gas supplied to the customers under the gas sales contract.

The arbitration for both claims is in process and the matter is sub judice. The Company believes that the outcome is not determinable.

The Company may not be able to supply gas to a customer in Hazira whose contract runs until April 2016. The Company has notified the customer that the underperformance of reservoir is a force majeure event. The customer does not agree with this position and has served a notice of arbitration on the Company. The arbitration is in process. The Company believes that the outcome is not determinable. Refer "Other Properties - India - Hazira Field" for details.

D6 Block

In a May 2012 letter, the GOI alleged that the D6 contractor group is 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 further asserted that certain joint venture costs are therefore disallowed for cost recovery. The contractor group is of the view that the disallowance of recovery of costs incurred by the joint operation has no basis in the terms of the PSC and that there are strong grounds to challenge the action of the GOI. The contractor group has commenced arbitration proceedings against the GOI challenging the allegations and the disallowance of cost recovery. In a July 2014 letter, the GOI updated their preliminary estimate of disallowed costs as at March 31, 2014 to $2.4 billion. To the extent that any amount of joint venture costs are disallowed, such amount would be removed from the calculation of profit petroleum, a portion of which would be payable to the GOI under the PSC. Because profit petroleum percentages for the contractor group and the GOI change as the contractor group recovers specified percentages of their investments, the potential impact on the GOI's share of profit petroleum is dependent on the future revenue and expenditures in the block and cannot be precisely determined. Based on the current profit petroleum percentage of ninety (90) percent for the contractor group and 10 percent for the GOI, if the GOI were to be successful in the cost recovery arbitration and the entire $2.4 billion ($238 million Niko share) of costs were disallowed, Niko's share of the potential impact would be a total of $24 million, of which $12 million would to relate periods up to March 31, 2015 and $12 million would relate to future periods. The GOI has also raised issues regarding other potential adjustments to the profit petroleum calculation and the contractor group has refuted these potential adjustments.

In October 2014, the Cabinet Committee of Economic Affairs of the GOI approved the new domestic gas pricing policy for India, effective November 1, 2014, and the GOI issued the Guidelines. The Guidelines indicate that the contractor group for the D6 Block will be paid the earlier price of $4.20 / MMbtu for gas sales from the Dhirubhai 1 and 3 fields and the difference between the revised price and the $4.20 / MMbtu will be credited to a gas pool account and "whether the amount so collected is payable or not to the contractors of this block would be dependent on the outcome of the award of the pending arbitration and any attendant legal proceedings".

Proceedings in Indonesia

The Tax Directorate General of Indonesia had assessed several oil and gas companies operating in Indonesia for LBT using a new framework which applies to PSCs signed subsequent to the implementation of a government regulation effective December 20, 2010. The Surface and Sub Surface assessments of LBT have been applied to offshore PSCs out of which majority of the assessed tax relates to Surface Area. The LBT assessments are being challenged by the impacted oil and gas companies and industry associations.

Certain of the Company's Indonesian subsidiaries holding interests in three (3) of its operated offshore PSCs (Obi, South East Seram and Aru) received assessment notices raising demands for a total of $31 million net for assessment years 2012 to 2014. Each subsidiary filed an objection letter with the tax department, which was subsequently rejected by the tax authorities. Each of the subsidiaries has filed an appeal in the tax court against objection decision of the tax department. The operator for two (2) of the Company's partner-operated offshore PSCs (North Ganal and Halmahera II) has also received 2012 to 2014 assessments totaling $5 million net and filed objection letters and appeals regarding these assessments.

For assessment year 2014, the Tax Directorate General has further amended its framework, which will result in nil surface assessments for LBT for 2014. Effective January 1, 2015, assessments for exploration PSCs have been exempt from LBT as a result of a change in the law by the Finance Ministry. Appeal hearings were conducted in May and June 2015, no conclusion has been drawn. The Company believes that it has a strong legal position against the taxes assessed from 2012 to 2014 and therefore has not recorded these amounts in its financial statements. In the event that the appeal is not successful, the subsidiaries of the Company could be liable for a penalty of up to 100 percent of the LBT tax owing in addition to the amount of assessed tax, for a potential liability of $61 million.

In April 2015, the Company closed on transactions for the sale of certain of its subsidiaries holding interests in four Indonesian PSCs (West Papua IV, Kofiau, Halmahera-Kofiau, and Aru) as the first phase of transactions under a definitive agreement executed in October 2014 with a subsidiary of Ophir. The Company has indemnified Ophir for any potential LBT obligations related to the subsidiary that owns an interest in the Aru PSC and at closing, would do so for the subsidiary that owns its interest in the North Ganal PSC.

Other

From time to time The Company is subject to, and is presently involved in, litigation or other legal proceedings arising in the conduct of its business. The Company does not anticipate that its financial position, results of operations or cash flow will be materially affected by the resolution of these legal proceedings.

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

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 ten (10) percent 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 (3) 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 and Convertible Notes is Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario.

INTERESTS OF EXPERTS

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Deloitte LLP prepared the Reserve Report referred to in this Annual Information Form. See "Statement of Reserves Data and Other Oil and Gas Information". Deloitte has signed their 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 Deloitte who participated in or who were in a position to directly influence the preparation of the 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 provided in the Company's 2015 Consolidated Financial Statements and Management's Discussion and Analysis. 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: Glen R. Valk, Vice President Finance & CFO

APPENDIX "A"

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

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2015, 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 ten (10) percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management/Board of Directors.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10 percent discount rate)			
			Audited (US$000s)	Evaluated (US$000s)	Reviewed (US$000s)	Total (US$000s)
Deloitte LLP	Niko Resources Ltd. Reserve estimation and economic evaluation March 31, 2015	Bangladesh	-	$69,964		$69,964
		India	-	$164,864		$164,864
		Total		**$234,828**		**$234,828**

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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T29 0R8

(Signed) Robin G. Bertram
Robin G. Bertram, P.Eng.
Partner

Execution Date: June 10, 2015

APPENDIX "B"

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

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

Management of Niko Resources Ltd. (the "Company") 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 and includes other information such as contingent resources data or prospective resources data.

An independent qualified reserves evaluators has evaluated the Company's reserves data, contingent resources data and prospective resources data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Board of Directors of the Company and the Reserves and Health, Safety & Environmental Committee 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 evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data, contingent resources data and prospective resources data with management and the independent qualified reserves evaluators.

The Board of Directors of the Company and the Reserves and Health, Safety & Environmental Committee of the Company 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 Reserves and Health, Safety & Environmental Committee, approved

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and prospective resources data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data and prospective resources data; and
(c) the content and filing of this report.

Because the reserves data, contingent resources data and prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

(Signed) William T. Hornaday
William T. Hornaday
Chief Operating Officer
Chairman, Reserves and Health, Safety & Environmental

(Signed) Vivek Raj
Vivek Raj
Director

(Signed) Steven K. Gendal
Steven K. Gendal
Director

(Signed) Kevin J. Clarke
Kevin J. Clarke
Interim Chief Executive Officer
Chairman of the Board

(Signed) E. Alan Knowles
E. Alan Knowles
Director

(Signed) Glen R. Valk
Glen R. Valk
VP Finance and Chief Financial Officer

(Signed) Joshua A. Sigmon
Joshua A. Sigmon
Director

June 24, 2015

APPENDIX "C"

NIKO AUDIT COMMITTEE CHARTER

1.0 Constitution

A standing committee of the Board of Directors ("Board") of Niko Resources Ltd. (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 Company'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 Company'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 Company'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 Company (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 (3) members of the Board of the Company;

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 Company;

4.4 as a minimum, one (1) 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 Company that regulate meetings and proceedings of the Board;

4.8 the Committee may invite such directors, officers or employees of the Company, 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, Annual Information Form 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 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 Company'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 Company'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.