International Petroleum Corporation

Annual Information Form

For the year ended December 31, 2017

Dated: March 30, 2018

International Petroleum Corp.

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GLOSSARY OF TERMS

"**Audited Financial Statements**" means the audited consolidated financial statements of the Corporation for the years ended December 31, 2017 and 2016.

"**AIF**" or "**Annual Information Form**" means this Annual Information Form prepared for the year ended December 31, 2017 and dated March 30, 2018.

"**Board**" means the Corporation's Board of Directors.

"**Cenovus**" means Cenovus Energy Inc. of Canada.

"**COGE Handbook**" means the 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), as amended from time to time.

"**Common Shares**" means the common shares in the capital of International Petroleum Corporation.

"**Crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**ERCE**" means ERC Equipoise Ltd.

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

"**Group**" means International Petroleum Corporation and its subsidiaries, or any one or more of them.

"**IFRS**" means the International Financial Reporting Standards as issued by the International Accounting Standards Board and the IFRS Interpretations Committee.

"**IPC**" or the "**Corporation**" means International Petroleum Corporation.

"**Lundin Petroleum**" means Lundin Petroleum AB.

"**MCR**" means the material change report dated February 26, 2018 filed by the Corporation in respect of certain reserves and resource information.

"**McDaniel**" means McDaniel & Associates Consultants Ltd.

"**MD&A**" means the Management's Discussion and Analysis of results of operations and financial condition of the Corporation for the year ended December 31, 2017.

"**Natural gas**" or "**gas**" means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds

"**NASDAQ First North**" means the Nasdaq First North Stock Exchange in Sweden.
.
"**NI 51-101**" means National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators.

"**Petroleum**" means (i) any naturally occurring hydrocarbons in gaseous or liquid state; (ii) any mixture of naturally occurring hydrocarbons in a gaseous or liquid state; or (iii) any petroleum (as defined in (i) or (ii) herein) that has been returned to a reservoir.

"**Prospect**" means a geographic or stratigraphic area in which the Corporation owns or intends to own one or more oil and gas interests, which is geographically defined on the basis of geological data and which is reasonably anticipated to contain at least one reservoir or part of a reservoir of oil and gas.

"**PSC**" means production sharing contract.

"**Reservoir**" means a subsurface rock formation containing an individual and separate natural accumulation of producible petroleum characterized by a single natural pressure system.

"SEDAR" means the Canadian Securities Administrator's System for Electronic Document Analysis and Retrieval.

"**Spin-Off**" means the transaction in 2017 under which Lundin Petroleum spun-off its oil and gas assets in Malaysia, France and the Netherlands into the Corporation and distributed the Common Shares, on a pro-rata basis, to Lundin Petroleum shareholders.

"**Transfer Agreements**" means the agreements dated April 7, 2017, under which all of the shares of International Petroleum BV (then known as Lundin Petroleum BV) and all of the shares of Lundin Services Ltd. were transferred to the Corporation in exchange for the issuance by the Corporation to Lundin Petroleum of an aggregate of 113,462,147 Common Shares.

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

"**Vermilion**" means Vermilion Energy Inc.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	United States dollar

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
°API	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) gravity scale
bbl	Barrel (1 barrel = 159 litres)
boe[(1)]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
Mcf	Thousand cubic feet
Bscf	Billion standard cubic feet
NGL	Natural gas liquid

[(1)] All volume references to boe are calculated on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) unless otherwise indicated. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This AIF contains statements and information which constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Actual results may differ materially from those expressed or implied by forward-looking statements. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this AIF, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

Forward-looking statements include, but are not limited to, statements with respect to:

- Our intention to continue to implement our strategies to build long-term shareholder value;
- The benefits of the Suffield acquisition;
- IPC's intention to review future potential growth opportunities;
- The ability of our high quality portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The integration of the Suffield-related operations into IPC;
- Potential future growth opportunities in North America;
- Organic growth opportunities in France;
- Results of infill drilling in Malaysia;
- Results of 3D seismic survey in France;
- Future development potential of the Suffield operations;
- Potential acquisition opportunities;
- Estimates of reserves;
- Estimates of contingent resources;
- Estimates of prospective resources; and
- Future drilling and other exploration and development activities.

Statements relating to "reserves", "contingent resources" and "prospective resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successfully.

Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks.

These include, but are not limited to:

- The risks associated with the oil and 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 reserves, resources, production, revenues, costs and expenses;

- Health, safety and environmental risks;
- Commodity price and exchange rate fluctuations;
- Interest rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental risks;
- Competition;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

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

References may be made in this AIF to “operating cash flow” (OCF), “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt”/”net cash” which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in the MD&A under “Non-IFRS Measures”.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Audited Financial Statements, the MCR, the MD&A (See "Cautionary Statement Regarding Forward-Looking Information" therein), the Corporation's Non-Offering Prospectus dated April 17, 2017 (See "Risk Factors" and "Forward-Looking Information" therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

This AIF contains references to estimates of gross and net reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves / resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves / resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel's January 1, 2018 price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported and aggregated by IPC in this AIF as being as at December 31, 2017.

The price forecasts used in the reserve audit / evaluation are available on the website of McDaniel (www.mcdan.com), and are contained in the "Statement of Reserves Data and Other Oil and Gas Information" below.

Light and medium crude oil reserves/resources disclosed in this AIF include solution gas and other by-products.

"2P reserves" means proved plus probable reserves. "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. "Possible reserves" are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Each of the reserves categories (proved, probable and possible) 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, possible) to which they are assigned.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on a project maturity and/or characterized by their economic status.

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as development unclarified. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable. Of the Corporation's 63.4 MMboe best estimate contingent resources (unrisked), 17.4 MMboe are light and medium crude oil, 7.4 MMboe are heavy crude oil and 38.6 MMboe are conventional natural gas.

References to "unrisked" contingent resources volumes means that the reported volumes of contingent resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

The contingent resources reported in the AIF are estimates only. The estimates are based upon a number of factors and assumptions each of which contains estimation error which could result in future revisions of the estimates as more technical and commercial information becomes available. The estimation factors include, but are not limited to, the mapped extent of the oil and gas accumulations, geologic characteristics of the reservoirs, and dynamic reservoir performance. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Group's control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in the AIF.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Chance of discovery is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. There is no certainty that any portion of the prospective resources estimated in the report audited by ERCE and summarized in this AIF will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources audited. Estimates of the prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated in the report audited by ERCE and summarized in this AIF cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates in the report audited by ERCE and summarized in this AIF.

Reserves and contingent resources audited by ERCE and evaluated by McDaniel, as applicable, have been aggregated in this document by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This AIF contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this AIF do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves".

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

INTRODUCTION

The information set out in this AIF is stated as at December 31, 2017, unless otherwise indicated.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERCE in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts.

The volumes are reported and aggregated by IPC in this AIF as being as at December 31, 2017.

The MCR, the MD&A and the Audited Financial Statements are incorporated by reference and may be accessed on the SEDAR website at www.sedar.com under the Corporation's profile or on IPC's website at www.international-petroleum.com.

Capitalized terms used but not defined, are defined in the Glossary of Terms.

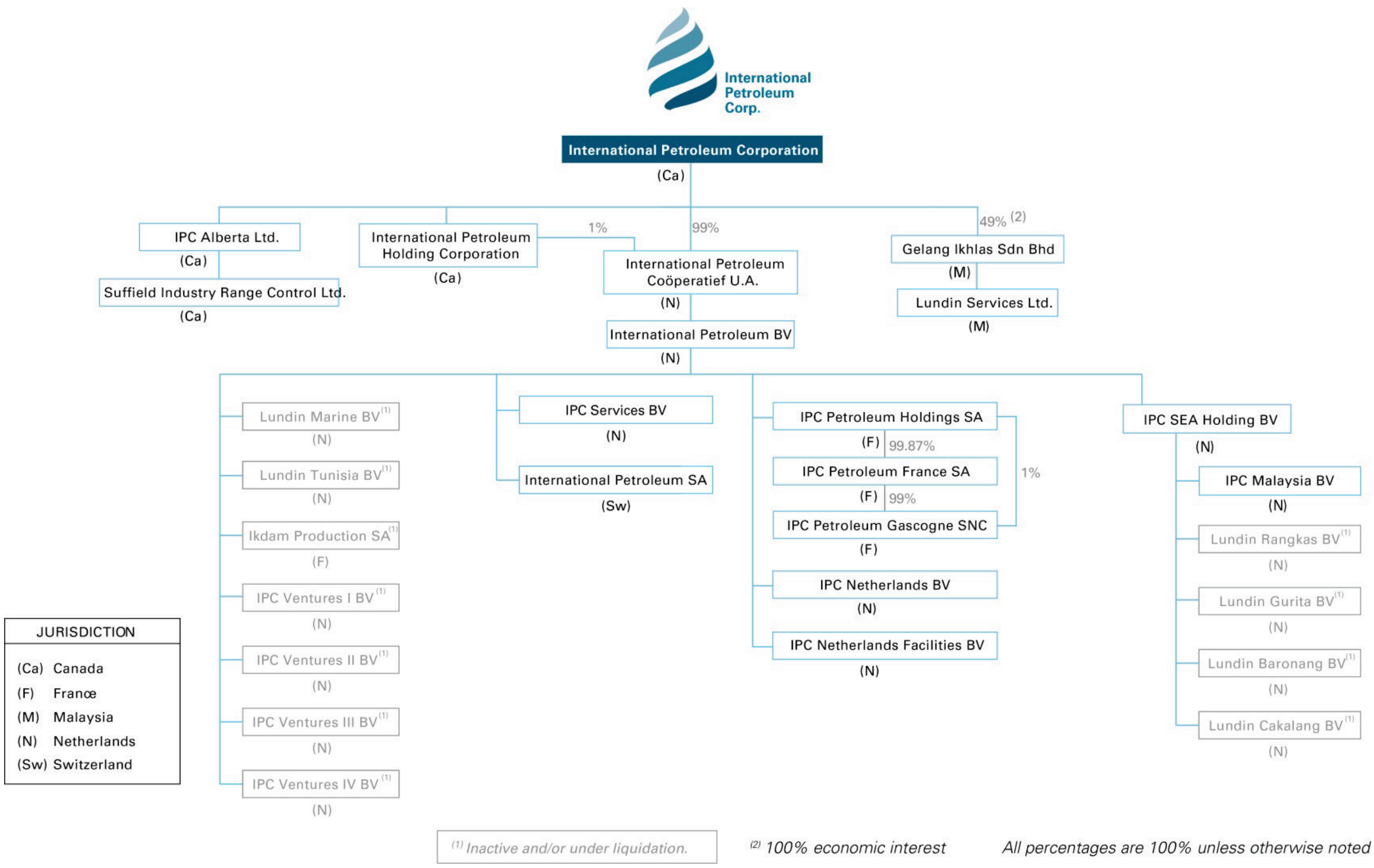
CORPORATE STRUCTURE

The full corporate name of the Corporation is International Petroleum Corporation. The Corporation's head office is located at Suite 2000, 885 West Georgia Street, Vancouver, British Columbia, Canada V6C 3E8 and the registered and records office is located at 2600, 595 Burrard Street Vancouver, British Columbia, Canada V7X 1L3.

IPC is a reporting issuer in Alberta and Ontario. The Common Shares trade on the TSX and NASDAQ First North under the symbol "IPCO".

International Petroleum Corporation was incorporated under the laws of the Province of British Columbia on January 13, 2017, under the name "1103721 BC. LTD." and domiciled in British Columbia, Canada under the Business Corporations Act (British Columbia) with British Columbia Registry number BC1103721. On January 23, 2017 the name of the Corporation was changed from "1103721 B.C. LTD" to International Petroleum Corporation.

Substantially all of the Corporation's business is carried on through its various subsidiaries. The following chart illustrates, as at the date of this AIF, the Corporation's significant subsidiaries, including their respective jurisdiction of incorporation and the percentage of voting securities in each that are held by the Corporation either directly or indirectly:



GENERAL DEVELOPMENT OF THE BUSINESS

In February 2017, Lundin Petroleum announced its intention to spin-off its oil and gas assets in Malaysia, France and the Netherlands into a newly formed company called International Petroleum Corporation and to distribute the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders (the "Spin-Off").

IPC acquired the Malaysian, French and Dutch assets through a series of reorganization transactions completed on April 7, 2017. In accordance with the Transfer Agreements between Lundin Petroleum and the Corporation dated April 7, 2017, all of the shares of International Petroleum BV (then known as Lundin Petroleum BV) and all of the shares of Lundin Services Ltd. were transferred to the Corporation in exchange for the issuance by the Corporation to Lundin Petroleum of an aggregate of 113,462,147 Common Shares based on a price of CAD 4.77 per Common Share, for aggregate consideration of USD 410 million plus working capital as at the effective date of January 1, 2017.

On April 24, 2017, the Spin-Off was completed and IPC's Common Shares commenced trading on the TSX and the Nasdaq First North under the ticker symbol "IPCO".

In May 2017, IPC decided to change the capital structure of the Corporation through a share purchase offer. The primary objective of the offer was to provide an orderly exit for Statoil ASA (a shareholder of Lundin Petroleum) as a large non-core shareholder of IPC and a potential risk to liquidity of the Common Shares. In June 2017, 25,540,302 Common Shares were purchased under the share purchase offer for a consideration of approximately USD 90 million. These Common Shares were subsequently cancelled through an internal reorganization, resulting in shareholder negative dilution of approximately 22.5 percent. The total number of issued and outstanding Common Shares following such cancellation was 87,921,846. A USD 100 million reserve based lending facility was put in place in April 2017 and drawn upon to facilitate completion of the share purchase offer.

In August 2017, IPC announced that the Corporation planned to drill two additional infill wells on the Bertam field in Malaysia during the fourth quarter of 2017. In addition, IPC planned to proceed with 3D seismic acquisition on the Villeperdue field in the Paris Basin, France. IPC also announced that following technical work undertaken by IPC's teams in France and Malaysia, the best estimate contingent resource base was 17.5 MMboe as at June 30, 2017.

In September 2017, IPC announced the acquisition of the Suffield area oil and gas assets in southern Alberta, Canada. The acquisition was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid by the end of June 2018. In addition, certain capped, additional contingent payments may become payable based on oil and natural gas prices. The acquisition was fully funded from internally generated cash flow and existing and new lending facilities. The acquisition financing package, consisting of an increase in the reserve based lending facility from USD 100 million to USD 200 million and new credit facilities of CAD 310 million, was fully underwritten by BMO Capital Markets.

In December 2017, IPC announced that drilling of the first of two planned infill wells had commenced on the Bertam field, offshore Malaysia. The two infill wells were successfully completed and put on production in early 2018.

In February 2018, IPC announced that, following the submission of an application to the relevant Malaysian authorities, the FPSO Bertam received registration as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

DESCRIPTION OF THE BUSINESS

Summary

The main business of IPC is exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia, France and the Netherlands with exposure to growth opportunities. Since listing the Common Shares on April 24, 2017 in Canada and Sweden, IPC has been focused on delivering operational excellence, demonstrating financial resilience, maximizing the value of IPC's resource base and targeting growth through acquisition.

The vision and strategy of IPC's management from the outset was to use the IPC platform to build an international upstream company focused on creating long term value for IPC's shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base.

As at December 31, 2017, the Group operated its produced volumes in the Paris Basin, France and Malaysia and owned non-operated interests in the Aquitaine Basin, France and the Netherlands. As operator, the Group is able to control the pace and strategy of its development activities and to implement execution strategies that are compatible with its approach to prudently managing operational and financial risk. The Group is also able to optimize the timing and magnitude of capital expenditure programs and to leverage the value of management's expertise and proven track record. In January 2018, the Corporation completed the acquisition of the Suffield area assets in Canada, which from such date are also operated by the Group.

For the full year 2017, IPC reported average daily production of 10,307 boepd. This production was driven by good performance across all of IPC's assets in Malaysia, France and the Netherlands. The uptime performance of the FPSO Bertam in excess of 99 percent continued during 2017, excluding the planned shutdowns for maintenance and infill drilling operations.

During 2017, IPC's assets generated operating cash flow of USD 138 million. This allowed IPC to fund operations and reduce the amounts drawn under the credit facility put in place to fund the purchase of 25.5 million Common Shares under the share purchase offer in the second quarter of 2017. By the end 2017, IPC was in a net cash position of USD 5.6 million, excluding the CAD 40 million (USD 32.6 million) deposit for the Suffield acquisition in Canada. Including the Canadian acquisition deposit, net debt as at December 31, 2017 was USD 26.3 million.

IPC's 2P reserve base amounted to 29.4 MMboe as at December 31, 2016. A portfolio re-evaluation during the first half of 2017 allowed IPC to book 17.5 MMboe of best estimate contingent resources as at June 30, 2017. A capital investment program was approved in the second quarter of 2017 to drill two new infill wells in Malaysia on the Bertam field and acquire a 79 km^2 3D seismic survey in the Villeperdue field in France.

As at end December 2017, IPC's 2P reserves were 129.1 MMboe, including 2P reserves attributable to the Suffield acquisition in Canada which completed on January 5, 2018. In addition, IPC reported best estimate contingent resources as at end December 2017 of 63.4 MMboe (unrisked), also after giving effect to the Suffield acquisition in Canada. Two additional infill locations on the Bertam field in Malaysia have been booked as well as the inclusion of the acquired resources in Canada.

IPC's oil and gas assets in Malaysia are offshore assets characterized by a small number of highly productive wells. Production is light, high quality oil that attracts a premium to Brent crude pricing. The Malaysian assets began production in 2015. As at December 31, 2017, there were 12 horizontal wells, fitted with electric submersible pumps and a natural aquifer drive for pressure support. The Corporation also indirectly holds a 100% economic interest in the FPSO Bertam operating in Malaysia.

IPC's oil and gas assets in France are comprised of two main operating basins, the Paris Basin, which is operated by the Group, and the Aquitaine Basin, which is operated by Vermilion. Both basins are characterized by a high number of wells with low production decline rates. Production from IPC's oil and gas assets in in France is light, high quality oil only. IPC's oil and gas assets in France had been under the ownership of Lundin Petroleum since 2002, are well known to the Corporation's management and are operated by the current local team in place in the Paris Basin and by Vermilion in the Aquitaine Basin.

IPC's oil and gas assets in the Netherlands are non-operated, late-life natural gas fields, both onshore and offshore, that continue to provide profitable production.

IPC's oil and gas assets in Canada were acquired in January 2018. During the third quarter of 2017, IPC announced the transformational acquisition of the Suffield area oil and gas assets in Alberta, Canada. The Suffield area oil and gas assets are high quality conventional assets that have been operated safely and efficiently for many years by Cenovus Energy Inc. ("Cenovus"). This acquisition fits with IPC's strategy of leveraging our existing producing asset base as a platform for value accretive acquisitions of long-life, low-decline producing assets in stable jurisdictions with upside development potential.

The transaction was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid at June 30, 2018. In addition, certain capped, additional contingent payments may become payable based on oil and gas prices. These contingent purchase price payments may become payable based on actual average monthly oil and natural gas prices during 2018 and 2019. Payments are due for each month when the average daily price of West Texas Intermediate (WTI) is above USD 55 bbl or natural gas prices at the Henry Hub are above USD 3.50 per million British thermal units (MMBtu). These payments are capped for each commodity on a per month basis (CAD 375,000 per month for oil and CAD 1,125,000 per month for gas) with a maximum combined payment of CAD 36 million in aggregate. The Group paid Cenovus CAD 375,000 in February 2018 related to oil prices realized in January 2018, with no amount owing related to January 2018 gas production.

Description of the Group's Oil and Gas Assets

The following is a description of the properties comprising the IPC's oil and gas assets in Canada, Malaysia, France and the Netherlands. The following property descriptions are as at December 31, 2017 unless otherwise indicated.

Canada

2017 Summary

In September 2017, IPC announced the transformational acquisition of the Suffield area oil and gas assets in Alberta, Canada.

The Suffield oil and gas assets are held over a large, contiguous land position of 800,000 net acres of shallow natural gas rights and 100,000 net acres of oil rights in southeast Alberta. These producing fields have future development potential from a combination of low risk development drilling, well stimulation and enhanced oil recovery (EOR) opportunities, which had not been undertaken for a number of years due to Cenovus' capital allocation priorities.

The Suffield area assets had been operated by Cenovus and its predecessors for more than 40 years. The oil is produced using conventional recovery methods via water drive with pumped multi-lateral horizontal wells. The production is collected in a network of pipelines and transported to a central processing facility, the 1-27 Battery.

Management of IPC believes that the oil upside relates to low risk development drilling. There is also low risk upside in Alkaline-Surfactant-Polymer (ASP) flood expansion. This process has been demonstrated to work in two fields, and IPC is evaluating its application into a third field which is near the existing infrastructure.

Sweet natural gas production in the Suffield area is via shallow wells producing from multiple formations. The wells produce into a network of natural gas pipelines with a number of compressor stations. IPC believes that the production is low maintenance with optimization potential.

IPC transitioned certain Cenovus employees who have the experience in managing and operating these assets across to IPC, including experience with and knowledge of the established maintenance routines and rigorous HSE procedures.

No oil wells have been drilled since 2014 and no gas wells have been drilled since 2010 due to Cenovus' capital allocation priorities.

Overview

The onshore Suffield Area oil and gas assets in Canada are situated in southeast Alberta and are operated by IPC. The oil assets are 100% working interest and gas assets are 99.6% working interest. These assets are characterized as having a high number of wells with low production decline rates. The oil quality is 13°API and is produced via conventional, non-thermal methods. The assets are well-known to the operational team in Redcliff, Alberta and to the asset management team in Calgary, Alberta, many of whom have been working the assets for many years as Cenovus employees.

Asset Description

Oil is produced primarily from open-hole horizontal wells pumped with progressive cavity pumps, gathered and processed at the 1-27 Battery and piped to market. The reservoirs are high quality Cretaceous sandstones with reservoir pressure supported by a combination of bottom water drive and water injection. There are two pools that are benefitting from ASP injection which entails a small amount of chemical being added to the injection water to mobilize more oil than would be recoverable by water drive alone.

The shallow conventional natural gas production is from a combination of five shallow horizons produced via vertical production wells. The low pressure wells are naturally flowing assisted with siphon strings in some cases. The majority of the produced natural gas is sold at Empress reference with the balance being sold at AECO reference.

Geologic Overview

The main oil producing horizon is the Cretaceous age Glauconitic (Manville group) sand. The sand was deposited in a shoreline / Aeolian environment and is generally of very high reservoir quality. Reservoir depth is approximately 1000 metres and oil is produced via water drive. The oil is viscous however with the good reservoir quality it can be produced via conventional, non-thermal methods.

The secondary oil reservoirs are Upper Mannville washovers, Lower Manville Ellerslie, and Lower Manville Detrital. Two of the wash-over pools are subject to ASP enhanced oil recovery.

The natural gas production is from a regional multi zone conventional play. The sands are part of the Belly River / Colorado group and are generally hydraulically fractured and commingled. Almost all of the natural gas production is from formations at less than 500 metres depth.

Production Operations

The vast majority of the oil production wells are activated by progressive cavity pumps and are tied into intra field collection lines. The oil density at surface conditions is 13°API. There is ample oil processing capacity to accommodate existing and future planned production.

Abandonment Obligations

Abandonment in Canada consists of permanent plugging of the wells, decommissioning of facilities and pipelines, and site restoration. A complete review of the wells, pipelines and facilities status is completed annually. Provisions for the abandonment activities are revised every year based on the latest information and these provisions are included in the capital expenditures budget. The Group follows the applicable Alberta regulations and reports regularly to the Alberta regulator their abandonment activities and cost estimates. On this basis, non-economic wells and/or non-producing wells are regularly abandoned as a part of ongoing business.

Infrastructure and Marketing

Oil is gathered at the 1-27 Battery, blended with condensate, and pipelined to market. The shallow natural gas is gathered into intra-field flow lines operated via 16 compressor stations. There are two egress points with the bulk of the natural gas going to Empress and the balance going to AECO.

Malaysia

2017 Summary

Net production from the Bertam field on Block PM307 (IPC working interest (WI) 75%) during 2017 was at 6.7 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime during 2017 was in excess of 99 percent (excluding planned shutdowns).

The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. In February 2018, following a corporate restructuring transaction, the FPSO Bertam was registered as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

In December 2017, drilling commenced on the first of two sanctioned infill wells on the Bertam field, with production commencing in January 2018. The second well commenced drilling in January 2018 and was completed and put on production in February 2018.

Reprocessing of Bertam 3D seismic that was acquired in 1996 with the latest technology was completed during the fourth quarter of 2017, allowing for a full review of additional infill targets. This allowed the booking of 1.4 MMboe of additional best estimate contingent resources as at 31 December 2017.

During the fourth quarter of 2017, the Group gave notice of its intention to withdraw from the PM328 exploration block. Final approval of the withdrawal was pending at the end of 2017 and was granted in February 2018. No commitments are outstanding on any blocks in Malaysia.

Overview

All of the Group's production and reserves in Malaysia come from the Bertam oil field located offshore Peninsular Malaysia. The Bertam field has been on production since April 2015. The Group is the operator of Block PM307 with a 75% working interest, with Petronas holding the remaining 25% through its wholly owned subsidiary Petronas Carigali Sdn Bhd ("PCSB").

The administrative, accounting and technical affairs of the Group's activities in Malaysia are managed from its office in Kuala Lumpur.

Bertam Field (Block PM307)

History

The Bertam field is located offshore Peninsular Malaysia on Block PM307 and was initially discovered in 1995 by the Bertam-1 well drilled by Petronas. PM307 was acquired by IPC's wholly-owned subsidiary IPC Malaysia BV in 2011 and was successfully appraised in 2012 and a field development plan was submitted and approved by Petronas in late 2013. An efficient execution of the development plan allowed the field to commence production in April 2015. The Bertam development consists of an unmanned wellhead platform and, as at December 31, 2017, 12 development wells producing to the FPSO Bertam.

Asset Description

The Bertam field is located 175 kilometres offshore to the east of Peninsular Malaysia, close to the Indonesian border at a water depth of about 74 metres. The field is a low relief, approximately 15 square kilometre, four-way closure. Maximum oil column is in the order of 20 to 25 metres. Reservoir depth is approximately 1600 metres below sea level and the reservoir was slightly underpressured at the first oil date in April 2015.

Geological Overview

The main reservoirs are Late Oligocene deltaic sandstones of the South Malay Basin K sequence. The main reservoir, K10.1, is a continuous sand with subtle variations in properties across the field. Gross thickness is in the 7 to 10 metres range, porosity is 20-25% and permeability is 80-300 milliDarcies.

Production Operations

The reservoir recovery mechanism is moderate to strong aquifer drive. As at December 31, 2017, reservoir access was through 12 horizontal producer wells placed close to the top of the K10.1 structure to minimize water coning. Since the reservoir is undersaturated with no gas cap, the wells require artificial lift using electric submersible pumps (ESP). Average quality of oil produced from the Bertam field is good with an API gravity of 37°. The wells are tied back to the FPSO Bertam where separation and storage takes place.

Bertam – Floating Production Storage and Offloading (FPSO) Unit

In 2013, Lundin Petroleum received development plan approval for the Bertam oil field on Block PM307 which integrated an unmanned wellhead platform tied to a floating production, storage and offloading vessel. Lundin Petroleum completed an extensive upgrade and life extension program on the FPSO Ikdam (renamed the FPSO Bertam), and it is now operating on the Bertam field in Block PM307.

Since the FPSO Bertam started receiving oil from the Bertam field in April 2015, it has achieved an excellent operational uptime of greater than 99 percent.

The FPSO Bertam is currently leased to the PM307 joint venture under a bareboat charter arrangement with a six-year fixed term at the daily lease rate to April 2021. There are a further four, one-year year options available after the fixed period. The daily operations and maintenance of the facility are undertaken by E&P O&M Services Sendirian Berhad, an operations and maintenance service provider in Malaysia, under contract and supervision of IPC Malaysia BV. E&P O&M Services Sendirian Berhad is a wholly-owned subsidiary of PCSB that offers operations and maintenance services in Malaysia. The operations and maintenance contractor and IPC Malaysia BV are responsible for the maintenance and upkeep of the FPSO Bertam.

FPSO Flagging in Malaysia

The FPSO Bertam is required to be Malaysian flagged in order to offload oil production from the Bertam field in Malaysian waters. Following the submission of an application to the relevant Malaysian authorities in 2018, the FPSO Bertam has now received registration as a Malaysian flagged vessel under the applicable Malaysian marine regulations.

Abandonment Obligations

The Bertam field obligations for abandonment are in line with the requirements set out by the Petronas Procedures and Guidelines for Upstream Activities (the "PPGUA"). In accordance with the PPGUA, the FPSO Bertam must be returned to Lundin Services Limited, it must be cleaned and be gas free and the wellhead platform must be removed to below the mud line. Wells will be abandoned in line with the PPGUA. A cash provision for the abandonment of facilities is made annually into the abandonment fund at a rate relative to the annual production volumes, as per the PSC requirements. The Group also makes provisions for the abandonment of wells annually, but costs are not paid until they are actually incurred.

Oil Export Infrastructure

The Bertam field utilizes the FPSO Bertam for production and oil storage. Export is undertaken directly from the FPSO to oil tankers via an offloading hose and offtake system.

Marketing

Oil produced from the Bertam field is sold on a spot tender to the highest bidder. The tender process is managed by Petronas, on behalf of the Group. The crude is delivered directly from the FPSO Bertam into the buyer's vessel. The price of the crude achieves a premium over the Brent crude price, which varies depending on the supply and demand balances in Asia.

Petronas, PCSB, IPC Malaysia BV and Petco Trading Labuan Company Limited ("Petco") are parties to a marketing agency agreement dated June 17, 2015. The marketing agency agreement is effective until December 31, 2019. Under the marketing agency agreement, Petronas, PCSB and IPC Malaysia BV appoint Petco as an exclusive marketing agent to sell Petronas', PCSB's and IPC Malaysia BV's respective entitlements of crude under the PM307 PSC. Petco is paid an agency fee based on barrels of crude oil sold.

Development Plans

During the July 2017 planned shutdown, a range of instrumentation and equipment with a higher pressure rating were put in place to allow for an increase on the Bertam wells which had been constrained due to pressure limitations.

A two well infill campaign was sanctioned in 2017 and began during the fourth quarter of 2017. The campaign was completed and the infill wells were brought on production in January and February 2018. Additional development and exploration potential has been identified in the Bertam field. IPC is currently evaluating the drilling of two additional infill wells which are analogous in concept to the recently executed A16 and A17 infill wells. There are spare slots on the wellhead platform to accommodate the new wells. The Group is also evaluating the I-35 prospect. See "Statement of Reserves Data and Other Oil and Gas Information".

Peninsular Malaysia – PM307 Gas Holding Area (Tembakau, Mengkuang)

The first exploration well by Lundin Petroleum was Tembakau-1, which was drilled in 2012 and was a natural gas discovery in two Miocene sandstone intervals. The discovery was successfully appraised with Tembakau-2 in 2014. Subsequently, Mengkuang-1 was drilled in October 2015 to test an oil prospect in the I-35 channel system and was a small natural gas discovery.

A gas holding area (GHA) application was approved in April 2017, and is effective from May 2016 until May 2021. The development of this asset is estimated to be sub-economic under current economic conditions and therefore development is presently considered not viable.

Sabah – SB 303 Gas Holding Area (Tarap, Cempulut, Berangan, Titik Terang)

Block SB303 is located at the northern tip of Borneo and has been explored by several rounds of operations since the late 1960s. In SB303, prior to the Group's operations, nine exploration wells were drilled, resulting in one small natural gas discovery (Titik Terang). The reservoirs are well-developed sandstone of mainly Miocene age.

IPC Malaysia BV made three marginal natural gas discoveries on Block SB303 with the Tarap, Cempulut and Berangan natural gas discoveries. IPC Malaysia BV applied for a GHA covering these three discoveries and the vintage Titik Terang discovery in March 2015, which was granted in April 2015 until April 2020. The development of this asset is estimated to be sub-economic under current economic conditions and therefore development is presently considered not viable.

France

In France, the Group's oil and gas assets are situated in the Paris Basin and the Aquitaine Basin. The majority of the production and reserves of the Group's oil and gas assets comes from the operated fields in the Paris Basin. In the Aquitaine Basin, production comes from Vermilion Energy Inc.'s ("Vermilion") operated fields, where there is a 50% working interest.

2017 Summary

Net production in France during 2017 was 2.4 Mboepd. IPC recognizes significant development upside in the Paris Basin. In parallel with maturing the contingent resources, IPC has been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base.

The Vert La Gravelle field has been on production since the mid-1980s and has long been recognized as a field with water-flood and development drilling upside. A field re-development project was sanctioned in 2014 however as a result of Lundin Petroleum's capital re-allocation priorities, the project was postponed after the construction and commissioning of the facilities and the drilling of the first two wells. IPC is taking the opportunity to revisit the development concept sanctioned in 2014 in particular IPC is investigating the merits of applying horizontal well technology as a means to optimize value.

In respect of the Villeperdue West project, the concept is to extend the development drilling to the west into an area that was considered to be water bearing when the initial field development was executed in the 1980s. Production trends on the west extension combined with our mapping and geologic assessment point towards significant bypassed oil potential which can be developed and tied into existing infrastructure. There remains structure and reservoir risk which is being addressed through the acquisition of 79 km^2 of high resolution 3D seismic approved in the second quarter of 2017. The 3D seismic acquisition was completed safely and within budget in October 2017.

Seismic processing, interpretation and subsequent reservoir development studies will continue through 2018. The seismic survey will also improve the structural definition of the Villeperdue Deep prospect.

The contingent resource estimates reported for France relate to development drilling and water-flood optimization opportunities. In all cases, the product type is light crude oil. The risk and uncertainty associated with the contingent resources in France is largely due to limited seismic coverage and understanding of structural extent of the fields. To recover the contingent resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. In all cases, the contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves.

France – Paris Basin

History

Production in the Paris Basin fields started in 1959. The main Villeperdue field started production in 1983. The assets were operated by Total Exploration and Société Nationale Elf-Aquitaine (Production) before being transferred to Coparex International S.A. (now known as Lundin International S.A.) in 1993 and 1995. Lundin Petroleum acquired the Paris Basin assets in 2002 when it bought Coparex International S.A. from BNP Paribas. In 2007, Lundin Petroleum acquired a further 20% interest in four assets from Carr Production France. In 2017, Lundin Petroleum's oil and gas assets in France were acquired by the Corporation in connection with the Spin-Off.

Assets Description

The Group is the operator of nine oil field licences and five exploration permits located approximately 100 kilometres east of Paris in the central part of the Paris Basin. The Group is the operator of all of the Paris Basin fields and holds a 100% working interest in eight of the nine producing fields (43.01% working interest in Dommartin Lettrée field with Vermilion as partner).

Geological Overview

There are two main productive horizons, namely, the Middle Jurassic (Dogger) limestones and Late Triassic (Rhaetic) sandstones. The Middle Jurassic Dogger reservoirs that are present in the Villeperdue, Merisier, and Soudron areas consist of oolitic and bioclastic limestones and are generally present within the central part of the Paris Basin. The Rhaetic sandstones extend into the northeastern part of the Paris Basin and provide the reservoirs for a number of oil fields, including Vert La Gravelle, Grandville, Dommartin-Lettrée, Soudron (which produces from both horizons) and Courdemanges.

Production Operations

The vast majority of production wells in the Paris Basin are activated by beam pumps. The injection wells are functioning with surface pumps. Oil is of good quality with 35 API gravity.

Six fields are operated by a production centre, Villeperdue, Merisier, Vert La Gravelle, Dommartin-Lettrée, Soudron and Grandville. Other fields have small gathering facilities where oil and water are separated from very small quantities of natural gas. Oil and water are then trucked to the nearest production centre where separation takes place. Produced water is reinjected in the reservoirs for pressure support.

Crude oil is trucked from the various production centres to the main Villeperdue gathering centre. Oil is sent to the Grandpuits refinery operated by Total SA via a pipeline owned by the Group.

Abandonment Obligations

Abandonment in France consists of permanent plugging of the wells, decommissioning of facilities and platforms and pipeline, and site restoration. A complete review of the wells and facilities status is completed annually on the Group's oil and gas assets in France.

Provisions for the abandonment costs are updated each year based on the latest information. The Group follows the French regulations on the subject and report regularly to the French administration their abandonment activities and cost estimates.

On this basis, non-economic wells and/or no longer producing wells are regularly abandoned as a part of ongoing business activity.

Infrastructure and Marketing

Crude oil is trucked from the various production centres to the main Villeperdue gathering centre. Oil is sent to the Total-operated Grandpuits refinery via a 100% owned pipeline. Oil is stored in tanks in the Villeperdue centre, which can hold approximately 16 days of the total Paris Basin production. It is then exported in batch mode and sold to Total under a contract with Total to the refinery.

Development Plans

A limited number of development campaigns have been implemented by Lundin Petroleum over the past 15 years focusing on development drilling opportunities and increasing water injection for pressure maintenance: Merisier in 2004, Grandville in 2011 and Vert La Gravelle in 2014. This latter development was suspended in 2015 following execution of the facility and pipeline work having drilled two wells of a seven well campaign due to the low oil price environment.

There is a renewed management focus on maturing organic growth opportunities in the Group's oil and gas assets in France, including a complete review of the remaining Vert La Gravelle development looking for areas of optimizing and capitalizing on current lower cost environment. Other opportunities are at concept stage which the company will mature and rank as technical work progresses. Execution of such opportunities could offset the already low natural decline rates.

France – The Aquitaine Basin

Assets Description

The Group has a 50% working interest in five production licences in the Aquitaine Basin. All licences associated with the Group's oil and gas assets are operated by Vermilion, who has the remaining 50% interest.

Fields are well developed with water injection for oil sweep and reservoir pressure support. The developments are constrained by the availability of surface locations resulting in wells that are long reach. All producing wells are activated by electric submersible pumps. Injector wells are equipped with surface injection pumps.

Geological Overview

The fields in the Aquitaine Basin produce from the Lower Cretaceous Purbeckian sandstones which are at a depth of 2,700 to 3,300 metres below sea level and are mainly tidal and fluviatile with generally good porosity and permeability. The fields are located either immediately under or adjacent to the Bay of Arcachon.

Production Operations

Oil is produced via water-flood drive and is of good quality with an °API gravity of 28 to 34. The production wells are equipped with electric submersible pumps.

Oil and water produced from Les Pins and Les Mimosas is transported by a pipeline network to Les Arbousiers where all the oil is transported by flowline to the Vermilion 50% owned and operated Cazaux field. The Group has a 50% interest in the pipelines. From Cazaux, oil is transported via a Vermilion owned and operated pipeline into the Ambes terminal, north of Bordeaux. In 2015, there was an issue with the flowline between Les Arbousiers and Cazaux resulting in a temporary production stoppage from Les Pins, Les Arbousier and Les Mimosas fields. Production has since resumed via trucking.

Abandonment Obligations

Abandonment in France consists of permanent plugging of the wells, decommissioning of facilities and platforms and pipeline, and site restoration. A complete review of the wells and facilities status is carried out every year by the Group and provisions for the abandonment activities are made every year based on the latest information.

On this basis non-economic and/or no longer producing wells are regularly abandoned as a part of ongoing business and there is no envisioned production centre abandonment planned in the short term.

The Group follows the French regulations on the subject and reports regularly its abandonment activities to the French administration.

Infrastructure and Marketing

Oil produced from the Aquitaine Basin is sold under a sales contract with Total. Approximately each 9 to 10 months, the Group charters its own tanker to transport its equity oil to the Total-operated refineries in Le Havre or Donges on the Northwest coast of France.

Development Plans

The Group supports the operator's study initiatives to identify further development opportunities in the joint venture Aquitaine Basin fields. There are no definitive drilling plans at present.

Netherlands

2017 Summary

Net production from the Netherlands fields during 2017 was 1.2 Mboepd.

The production from the F15 field was permanently shut-in in December 2017 as planned. The facilities will be made hydrocarbon free and put on light-house mode. Testing of the Nieuwehorne-2 exploration well was completed during the fourth quarter of 2017, and the results are being evaluated.

Overview

The Netherlands is the second largest natural gas producer in Europe. It is now a mature hydrocarbon country as onshore production began in the 1950s and offshore production in the 1960s.

The Ministry of Economic Affairs (the "MEA") is responsible for the optimal development of oil and gas resources in the Netherlands. All oil and gas activity is governed by the terms outlined in the 2003 Mining Law, which provides the statutory framework for licensing, decommissioning and abandonment, Dutch State participation and financial obligations of licensees. The Netherlands introduced an open licensing system in 1995 in an effort to maintain exploration activity levels on the Dutch continental shelf. Under this system, all unlicensed acreage is available for allocation at any time during the year.

State participation occurs in the Netherlands via Energie Beheer Nederland BV ("EBN"), which acts as an independent partner in the majority of Dutch fields.

New discoveries can be feasibly developed because infrastructure is already in place. This infrastructure plays an important role in maximizing recovery from the sector and owners are working on delaying decommissioning and accelerating near-field developments. Efforts such as the Marginal Fields tax incentive and Fallow Acreage Covenant, which became effective in September 2010, are the latest measures that the Dutch government has taken to encourage exploration and ongoing development on idle acreage.

Assets Description

In the Netherlands, the Group's oil and gas assets are located in the southern and eastern part of the Southern North Sea gas province and onshore northern Netherlands. The Netherlands is a mature gas province providing the Group with low decline onshore and offshore production as well as providing upside potential through infill and exploration opportunities. The Group has varying interests in 20 licences and concessions of which 18 are producing licences and concessions and two are exploration licences and concessions. All of the licences and concessions held in the Netherlands are non-operated interests. Operators of the assets are large exploration and production companies in the Netherlands including Vermilion Energy Netherlands BV ("Vermilion NL"), Total E&P Nederland BV ("Total"), Engie E&P Nederland BV ("Engie") and Oranje-Nassau Energie BV ("ONE"). In the Netherlands, the natural gas pricing is based upon the European gas base pricing reference point.

The administrative, accounting and technical affairs of the Group's activities in the Netherlands are managed from its office in The Hague.

This portfolio provides stable cash flow and exposure to a variety of hydrocarbon plays with reservoir targets at Carboniferous, Rotliegendes, Zechstein, Triassic, Jurassic and Lower Cretaceous intervals. These fields produce by natural pressure depletion, aided by compression.

Most of the natural gas is sold to GasTerra, a company joint owned by the Dutch Government and Shell/ExxonMobil.

The productive horizons in the Group's portfolio of natural gas fields will be generally of Permian or early Triassic age. In the offshore portfolio, the main reservoirs are the upper and lower Slocheteren sandstones, and onshore the main reservoir is the Zechstein fractured carbonate with the secondary reservoirs being Vlieland and/or Rotliegend sandstones. Structurally, the fields, both onshore and offshore, tend to have faulting with the degree of compartmentalization varying from field to field.

Netherlands Onshore

The Group has interests in seven onshore licences and concessions, five production licences and concessions and two exploration licences and concessions. All the licences and concessions are operated by Vermilion NL. The onshore blocks are located in the northern part of the Dutch mainland.

The main onshore assets of the Group in the Netherlands are located in the Gorredijk and Slootdorp licences, where recent discoveries, such as the Vinkega and Langezwaag fields, and the Slootdorp 6 & 7 wells have made considerable contributions to field production.

The onshore fields have dedicated processing and dehydration treatment facilities in the vicinity of the concessions in the north of the Netherlands, which are operated by Vermilion NL. The Group has an interest in the following treatment facilities: Harlingen Treatment Centre which supports the Zuidwal and Leeuwarden West fields, the Garijp Treatment Centre, which supports the Gorredijk, Oosterend and Leeuwarden East fields, plus third-party field users generating considerable sharing benefits and tariff income. The Slootdorp and associated fields are treated through their own facilities, the Middenmeer Treatment Facilities. Processed gas is directly exported from these treatment facilities into the Gasunie-operated sales gas network.

Netherlands Offshore

The Group's offshore main portfolio in the Netherlands consists principally of acreage centred on the K and L blocks in which the predominant play is the Slochteren Formation of the Lower Permian. Elsewhere the F6 and F15 blocks are located at the southern extent of the Dutch Central Graben and block Q16a is located close to the Dutch mainland near the Rotterdam gas terminal.

The Group in the Netherlands has interests in a number of offshore platforms, subsea developments, offshore wells and the related infrastructure. Broadly, offshore natural gas production is concentrated in a core area in the K, L and E blocks. Production from the K4a/K5b is treated at the K5-P platform and transported through the Wintershall-operated, Westgastransport ("WGT") pipeline system to Den Helder.

In the K6, L7 area treated gas from the K6-PP platform, on K6-C, is transported to Uithuizen via the K9C A platform and the Engie-operated L10 platform where it enters the Noordgastransport ("NGT") pipeline system. Production from the L4a fields is currently brought to the L7-C Central complex from which point the processed gas is also exported to the L10 complex and routed along the NGT pipeline.

Gas production from the F15 and F3 fields is exported via the Northern Offshore Gas Transport ("NOGAT") pipeline system, operated by Nederlandse Aardolie Maatschappij BV ("NAM"), to Den Helder. Gas production from the Q16-FA single well subsea development is tied back to a TAQA (the Abu Dhabi National Energy Company, PJSC)-operated platform and pipeline.

Abandonment Obligations

The Group is obliged to pay its proportion of the abandonment cost of their assets, facilities, pipelines and site restoration and are making abandonment provisions. The respective operators periodically carry out studies regarding the methodology to be applied together with the associated cost and provide abandonment cost estimates to partners.

In the offshore fields to date, other than the occasional abandonment of existing wells to make well slots available for new wells, there have been no planned field abandonments. The first field that is forecast to be abandoned is the L7 area facilities, and the operator (Total) is currently working on the abandonment plans.

Infrastructure - Upstream Gas Pipelines

Two major offshore pipeline systems (NGT and WGT) were built during the 1970s to serve the central Netherlands offshore gas province. The third major trunkline (NOGAT) was constructed in the early 1990s to evacuate gas from the northern offshore sector. The NGT pipeline is owned by Noordgastransport BV, a private limited liability company owned by PensionDenmark, Engie, InfraVia, ExxonMobil and Rosewood, and is operated by Engie. The WGT pipeline is owned by EBN, NAM (a 50-50 joint venture of Shell and Exxon/Mobil), ONE, Total, Tullow Exploration & Production BV and Wintershall Noordzee BV, and is operated by NAM. The NOGAT pipeline is owned by Northern Offshore Gas Transport BV, a private limited liability company owned by EBN, Engie, Total, Centrica Production Nederland BV and PGGM, and is operated by Engie.

Gas from the assets operated by Total is sent to the shore via WGT (Western licences, K4bK5a) and NGT (Eastern licences, K6L7, K5F, L4a) pipelines. Gas production from F3 (Engie-operated) and F15 (Total-operated) licenses transit via the NOGAT pipeline. Production from E17 (Engie-operated) is sent to shore via the NGT pipeline.

Domestic Gas Infrastructure and Interconnections

The Netherlands have a well-developed onshore gas network to serve household consumers, heavy industry and gas-fired power stations as well as servicing imports and exports of gas. The domestic gas pipeline infrastructure consists of high-pressure transmission gas pipelines to which regional distribution pipelines connect. The high-pressure network is owned by Gasunie and operated by the national gas transmission system operator Gasunie Transport Services BV, a wholly-owned subsidiary of Gasunie.

The regional networks are owned and operated by regional distribution system operators. Both the transmission system operator and distribution system operators are unbundled from production, trade and supply undertakings and manage the network subject to a fully regulated third party access regime, with conditions and tariffs set by the Netherlands Authority for Consumers & Markets, the designated national regulatory authority for the Dutch electricity and gas sector.

The Group’s onshore assets use the domestic gas pipelines.

Gas Marketing

Historically, the natural gas pricing mechanism, referred to as NIP, was primarily linked to the price of oil; however, with the opening of the spot market for gas, the GasTerra pricing mechanism has from 2013 changed to a spot market-based pricing mechanism using the Title Transfer Facility (the “TTF”) as a reference point. The TTF is a virtual trading point for gas sales in the Netherlands and is similar to the NBP (National Balancing Point) in the United Kingdom. The sellers can opt for different nomination regimes with each regime attracting a different pricing mechanism. These are: “as produced”, “buyers nomination” and “sellers nomination”. The Total- and Engie-operated fields sell under “sellers nomination”. The Vermilion NL- and ONE-operated fields sell under “as produced”. The “as produced” regime is used for smaller, more depleted fields where it is more difficult to forecast daily quantities.

GasTerra is obliged to purchase all the gas from gas fields in the Netherlands at market prices and conditions; however, the producers are not obliged to sell to GasTerra.

IPC Netherlands BV sells all its gas, other than for the K4K5 and E17A field, to GasTerra. The K4K5 gas is sold to Total and the E17A field is sold to RWE Supply & Trading GmbH, both on a European gas spot basis. In all cases, IPC Netherlands BV markets its gas jointly with its respective operators and partners.

Development Plans

The Dutch government continues to encourage investment through its small gas field policy. As a result, several development and exploration projects are ongoing which are intended to increase production.

The operators of the Group’s oil and gas assets in the Netherlands are currently working on reducing operating costs to extend field lives and to add volumes to the existing infrastructure through exploration and development activities with some success. The onshore business benefits from infrastructure owned by field joint venture partners that provides third party tariff income.

Geology

Overall, the Netherlands is a gas-prone hydrocarbon country with few oil fields. The thicknesses of coal-bearing, organic-rich Carboniferous sediments throughout the country have proved to be a prolific source rock. Post-Carboniferous sedimentation resulted in the burial of these source rocks to depths of some 4,000 to 6,000 metres. The generation of gas occurred over a wide area.

Discontinued Operations

The Corporation indirectly owns certain other oil and gas assets, which are not material to the Corporation.

Indonesia

Lundin Gurita BV, a member of the Group, holds an interest in the Gurita Block PSC which has ceased operations. In 2013, the Indonesian fiscal authorities claimed taxes from Lundin Gurita BV of approximately USD 22 million related to the surface area of the Gurita Block. Lundin Gurita BV disputes the validity of this claim and has challenged the tax in the Indonesian courts. Lundin Petroleum has agreed to indemnify Lundin Gurita BV in respect of any potential liability with respect to this dispute. Following resolution of the tax matter, the Gurita Block will be relinquished or disposed of and Lundin Gurita BV will be liquidated.

Lundin Baronang BV and Lundin Cakalang BV, members of the Group, hold interests in the Baronang and Cakalang Block PSCs, which have ceased operations and for which notices of relinquishments have been made. Following relinquishment of the blocks, each of Lundin Baronang BV and Lundin Cakalang BV will be liquidated.

Tunisia

Lundin Tunisia BV, a member of the Group, is a party to the Oudna concession agreement and joint operating agreement related to the Oudna field, offshore Tunisia. Operations on the Oudna field ceased since 2012 and the field was abandoned with no remaining operational liabilities. Lundin Tunisia BV's interest in the Oudna agreements is expected to be terminated and the company will be liquidated following resolution of certain matters with the Tunisian authorities. In December 2015, the International Centre for Settlement of Investment Disputes in Paris ordered the Tunisian State to pay approximately USD 22 million to Lundin Tunisia BV in respect of defaulted cash calls and past costs related to the Oudna field. The Tunisian fiscal authorities have made claims against Lundin Tunisia BV in respect of Tunisian taxes related to the Oudna field, which currently amounts to USD 12 million plus penalties and interest. The Tunisian authorities have also claimed approximately USD 2 million from Ikdam Production SA, a member of the Group. Lundin Tunisia BV disputes these claims and will continue to discuss an amicable settlement to these matters and/or enforcement of the International Centre for Settlement of Investment Disputes decision.

Ikdam Production SA, previously held an interest in the FPSO Bertam (then known as the FPSO Ikdam), which was contracted to operate at the Oudna field. The Tunisian fiscal authorities have made a claim against Ikdam Production SA in respect of Tunisian taxes. It is expected that these claims will be discussed in connection with the above-described Tunisian disputes with respect to Lundin Tunisia BV. Following resolution of those matters, Ikdam Production SA will be liquidated.

Management of the Corporation does not expect the Corporation to be liable for taxes claimed against either Lundin Tunisia BV or Ikdam Production SA and no contingency has been accounted for in the Audited Financial Statements.

Cambodia

IPC Ventures IV BV, a member of the Group, held an interest in Block E, offshore Cambodia. The Block E PSC has expired. There was an outstanding well commitment in respect of this block amounting to approximately USD 2.6 million, net to IPC Ventures IV BV, which is being discussed between the operator and the Cambodian authorities. Following final closure of the Block E PSC, IPC Ventures IV BV will be liquidated.

Employees

As of December 31, 2017, IPC had a total of 126 employees located in Malaysia, France, Switzerland and The Netherlands providing the Group with the managerial, operational, technical, financial and locally specific knowledge and experience to ensure effective and efficient management of IPC's oil and gas assets.

The Group maintains an operations office in Switzerland, where certain technical, legal, financial and other administrative functions are performed, and has local offices in Malaysia, France, The Netherlands and Canada. IPC established its Canadian office in Calgary in December 2017 in view of the closing of the Suffield area acquisition which occurred on January 5, 2018. The total number of employees as at March 1, 2018 was 230.

The following table summarizes IPC’s full-time equivalent employees as at December 31, 2017:

	December 31, 2017
Malaysia	59
France	47
Switzerland	15
The Netherlands	5
Number of employees	126

Specialized Skill and Knowledge

The Corporation relies on the specialized skills and knowledge required to explore for, develop and produce oil and natural gas. These skills include: (a) gathering, interpreting and processing technical data (such as geological and geophysical information); (b) designing, drilling and completing wells; (c) marketing oil and natural gas production; and (d) analyzing potential acquisition or development opportunities.

The Group employs teams of technical, commercial, financial and management staff in each of its areas of operations. In addition, various specialized consultants are available to assist us in areas where the Group does not require full time employees.

The Corporation is led by an experienced management team with a successful track record in the oil and gas industry. Each individual on the Corporation’s management team has 10 to 25 years of oil and gas industry experience, including substantial experience working directly with the Group’s oil and gas assets and in jurisdictions worldwide. In addition, the Board is comprised of individuals with an average of over 30 years of oil and gas and natural resources industry experience in very senior positions and a proven track record of creating value for shareholders, both organically and inorganically.

Competitive Conditions

The oil and gas industry is very competitive in the areas where the Corporation currently operates and may operate in the future. The Corporation competes for reserve acquisitions, licences and concessions, and skilled technical personnel with a substantial number of other oil and gas companies, many of which may have greater technical or financial resources.

The Group attempts to mitigate the risks associated with competition in exploration, production and marketing by operating in areas where IPC believes that its technical and commercial personnel have in-depth knowledge and understanding, for example in Malaysia and France. In respect of the acquisition of the Suffield area assets in Canada, an important factor for IPC was the availability of skilled and experienced personnel to transition across to the Group, for the current operations as well as for the future development of those and potentially other assets.

Cyclical Nature of Operations

IPC’s business and operations are generally not cyclical. However, operational results and financial condition are dependent on prices received for oil and natural gas production. Oil and natural gas prices have been volatile and are determined by a number of factors, including global and local supply and demand factors, weather, general economic conditions as well as conditions in other oil and natural gas producing and consuming regions.

In addition, the production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including "freeze-up" and "break-up", could affect access in certain circumstances. See also “**Risk Factors**”.

Environmental Regulations

The Group’s oil and gas operations are in regions where there are environmental regulations including restrictions on where and when oil and gas operations can occur, releases to the atmosphere and surface land and the potential routing of pipelines or location of production facilities. IPC attempts to mitigate the risk of inheriting environmental liabilities when conducting due diligence on acquisition opportunities. The Group will insure against such liabilities in accordance with industry practice. The Group will not fully insure against all of these risks, nor are all such risks insurable. Compliance with such regulations may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on IPC’s financial position. See also “**Risk Factors**”.

Social and Environmental Policies -- Sustainability

IPC conducts its business responsibly, exploring for and producing oil and gas in an economically, socially and environmentally responsible way. IPC respects human rights and protects the health and safety of employees and the natural environment. The Corporation promotes a strong safety culture across the Group in which the value of safety is embedded at all levels, guided by prevention and vigilance, and where risks are systematically assessed. IPC's environmental approach is based on understanding the operating environment in order to assess potential risks and take appropriate preventive measures.

The Group complies with laws and regulations, and seeks best industry practice to maintain operational efficiency through continuous improvement.

IPC's Code of Ethics and Business Conduct guides its directors, officers and employees in maintaining the commitments. Implementation is ensured through specifically tailored Policies, Procedures and Management Systems that apply to all activities of the Group.

IPC's Code of Ethics and Business conduct may be accessed on the SEDAR website at www.sedar.com under the Corporation's profile or on IPC's website at www.international-petroleum.com.

RISK FACTORS

IPC is engaged in the exploration, development and production of oil and gas and its operations are subject to various risks and uncertainties which include but are not limited to those listed below. The risks and uncertainties below are not the only ones that the Group faces. Additional risks and uncertainties not presently known to the Group or that the Group currently considers immaterial may also impair the business and operations of the Group and cause the price of the IPC's shares to decline. If any of the following risks actually occur, the Group's business may be harmed and the financial condition and results of operations may suffer significantly.

Exploration, Development and Production Risks: Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Group depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves associated with the Group's oil and gas assets at any particular time, and the production therefrom, will decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and natural gas will not be discovered or acquired by the Group. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In accordance with industry practice, the Group will not fully insure against all of these risks, nor are all such risks insurable. The Group maintains liability insurance in an amount that it considers consistent with industry practice. Due to the nature of these risks, however, there is a risk that such liabilities could exceed policy limits, in which event the Group could incur significant costs.

Volatility in Oil and Gas Commodity Prices: The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in Europe, Asia, the United States, Canada and elsewhere, the actions of OPEC, governmental regulation, political instability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports, the availability of alternative fuel sources and the potential for increased supply of oil and gas for unconventional shale oil and shale gas and other services.

Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the carrying value of the reserves and resources, borrowing capacity, revenues, profitability and cash flows associated with operation of the Group's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's assets.

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; issues and failures affecting the FPSO Bertam; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

Uncertainties Associated with Estimating Reserves and Resources Volumes: There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and resources (contingent or prospective) and the future cash flows attributed to such reserves and resources. The cash flow information associated with reserves and resources set forth herein are estimates only. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves and resources associated with the Group's assets will vary from estimates thereof and such variations could be material. Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

In accordance with applicable securities laws, the Group and the Group's independent reserves auditors have used forecast prices and costs in estimating the reserves, resources and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". See also "**Reserves and Resource Advisory**" above.

Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment: Oil and natural gas operations (including exploration, development, 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. Governments may regulate or intervene with respect to exploration, production and abandonment activities, price, taxes, royalties and the exportation of oil and natural gas. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the costs associated with the Group's oil and gas assets, any of which may have a material adverse effect on the business, financial condition, results of operations and prospects of the Group's oil and gas assets. In order to conduct oil and gas operations, the Group will require regulatory permits, licences, registrations, approvals, authorizations and concessions from various governmental authorities. There is a risk that the permits, licences, registrations, approvals, authorizations and concessions currently granted to the Group will not be renewed or that the Group will be unable to obtain all of the permits, licences, registrations, approvals, authorizations and concessions that may be required to conduct operations that it may wish to undertake.

In 2017, the French government enacted legislation to cease granting new petroleum exploration licenses in France and to restrict the production of oil and gas under existing production licenses in France from 2040. The Group continues to work closely with other industry participants and the French authorities with respect to this legislation. IPC does not expect that this legislation will have a material adverse effect on the Group's operations or financial condition.

FPSO Flagging Regulations in Malaysia: The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. In February 2018, following a corporate restructuring transaction, Malaysian flagging status for the FPSO Bertam was confirmed by the Malaysian authorities. As the FPSO provides a significant revenue stream, a failure to maintain the flagging status may result in a reduction of earnings for the Group and may also have a significant impact on offloading of crude from the FPSO Bertam.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions: The Group may make acquisitions and dispositions of businesses and assets in the ordinary course of business, including the recent acquisition of the Suffield area assets in Canada. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Group's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Group. In addition, non-core assets may be periodically disposed of, so that the Group can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Group, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Group.

Reliance on Third-Party Operators: The Group has partners in each of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France and the Netherlands, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group.

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects.

Credit Facility: The Group is party to credit facilities with international financial institutions. The terms of these facilities contain operating and financial covenants and restrictions on the ability of the Group to, among other things, incur or lend additional debt, pay dividends and make restricted payments, encumber its assets, sell assets and enter into certain merger or consolidation transactions. The failure of the Group to comply with the covenants contained in these facilities could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Group.

Competition for Resources and Markets: The international petroleum industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that may have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves and resources in the future depends not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory and development drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Marketing: A decline in the Group's ability to market oil and gas production could have a material adverse effect on its production levels or on the price that the Group receives for production, which in turn may affect the financial condition of the Corporation and the market price of the Common Shares. IPC's business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities as well as, potentially, rail loading facilities and railcars. Applicable regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect IPC's ability to produce and market oil and gas. If market factors change and inhibit the marketing of production, overall production or realized prices may decline, which may affect the financial condition of the Corporation and the market price of the Common Shares.

Hedging Strategies: From time to time, the Group may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases. Similarly, from time to time, the Group may enter into agreements to fix the exchange rate of certain currencies. However, if a currency declines in value compared to another currency, the operation of the Group's assets will not benefit from the fluctuating exchange rate if an agreement has fixed such exchange rate.

Climate Change Legislation: The oil and natural gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is a risk that any such programs, laws or regulations, if proposed and enacted, will contain emission reduction targets which the Corporation cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Implementation of strategies by any level of government within the countries in which the Corporation operates, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the operations and financial condition of the Corporation. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation, transportation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Fraud, Bribery and Corruption: The operations relating to the Group’s oil and gas assets are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. While the Corporation has implemented an anti-corruption compliance program across the Group, the Corporation cannot guarantee that the Group’s employees, officers, directors, agents, or business partners have not in the past or will not in the future engage in conduct undetected by the processes and procedures to be adopted by the Corporation and for which the Corporation might be held liable under applicable anti-corruption laws. Despite the Corporation’s compliance program and other related training initiatives, it is possible that the Corporation, or some of its subsidiaries, employees or contractors, could be subject to an investigation related to charges of bribery or corruption as a result of the unauthorized actions of its employees or contractors, which could result in significant corporate disruption, onerous penalties and reputational damage.

Decommissioning, Abandonment and Reclamation Costs: The Group is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Group’s assets at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates. Laws, regulations and contractual requirements with regard to abandonment and decommissioning may be implemented or amended in the future.

Third-Party Credit Risk: The Group may be exposed to third-party credit risk through the contractual arrangements associated with the Group’s assets with its current or future joint venture partners, marketers of its petroleum and natural gas production, third party uses of its facilities and other parties. In the event such entities fail to meet their contractual obligations in respect of the Group’s assets, such failures may have a material adverse effect on the Group’s business, financial condition, results of operations and prospects.

Repatriation of Earnings: A significant portion of the revenue-generating operations of the Group’s assets is located in Malaysia. In December 2016, the Central Bank of Malaysia implemented measures to facilitate its management of foreign exchange risk. These rules are not expected to have a material adverse effect on the Group, but there is a risk that the Central Bank of Malaysia or another authority may implement further measures that will restrict the future repatriation of earnings.

Expiration and Renewal of Licences, Leases and Production Sharing Contracts: Certain properties constituting the Group’s oil and gas assets are held in the form of licences, leases and PSCs. If the holder of the licence, lease or PSC or the operator of the licence, lease or PSC fails to meet the specific requirement of a licence, lease or PSC, including compliance with environmental, health and safety requirements, the licence, lease or PSC may terminate or expire. There is a risk that the obligations required to maintain each licence, lease or PSC will not be met. The termination or expiration of the licence, lease or PSC, or the working interests relating to a licence may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group’s oil and gas assets. From time to time, the licences and leases may, in accordance with their terms, become due for renewal; there is a risk that these licences, leases and PSCs associated with the Group’s oil and gas assets will not be renewed by the relevant government authorities, on terms that will be acceptable to the Corporation. There also can be significant delay in obtaining licence renewals which may already affect the operations associated with the Group’s oil and gas assets.

Litigation: In the normal course of the Group’s operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Group and as a result, could have a material adverse effect on the Group’s assets, liabilities, business, financial condition and results of operations.

Economic and Political Developments in Countries in which the Group Operates: International operations are subject to political, economic and other uncertainties. The Group’s assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia, France and the Netherlands, which could have a negative impact on the Group.

Terrorism and Sabotage: If any of the properties, wells or facilities comprising the Group’s assets is the subject of terrorist attack or sabotage, it may have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

Information Security: The Group is heavily dependent on its information systems and computer based programs. Failure, malfunction or security breaches by computer hackers and cyberterrorists of any such systems or programs may have a material adverse effect on the Group’s business and systems, potentially affecting network assets and people’s privacy.

The Group manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to the Group include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage.

Potential Conflicts of Interest: Certain of the individuals who are directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions.

Significant Shareholder: Nemesia S.à.r.l., 100% of the shares of which are owned by a trust settled by the late Adolf H. Lundin, owns approximately 33% of the aggregate voting shares of the Corporation. Nemesia S.à.r.l.'s holding allows it to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia S.à.r.l. maintains a significant interest in the Corporation, it is likely that Nemesia S.à.r.l. will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia S.à.r.l. will not be aligned with the interests of other shareholders.

Management Estimates and Assumptions: In preparing consolidated financial statements in conformity with IFRS, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Group must exercise significant judgment. Actual results for all estimates could differ materially from the estimates and assumptions used by the Group, which could have a material adverse effect on the Group's business, financial condition, results of operations, cash flows and future prospects.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting: Effective disclosure controls and procedures and internal controls over financial reporting are necessary for the Group to provide reliable financial and other disclosures and to help prevent fraud. The Group cannot be certain that the procedures it undertakes to help ensure the reliability of its financial reports and other disclosures, including those imposed on it under Canadian securities laws, will ensure that it maintains adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Group's results of operations or cause it to fail to meet its reporting obligations. If the Group or its independent auditor discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Group's consolidated financial statements and harm the trading price of the common shares.

Income Taxes: Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Group's assets. Furthermore, there is a risk that the relevant tax authorities will not agree with management's calculation of the income for tax purposes associated with the Group's assets or that such tax authorities will change their administrative practices to the detriment of the Group. In the event of a successful reassessment of the Group's income tax returns, such reassessment may have an impact on current and future taxes payable.

Additional Funding Requirements: The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's funds from operations is not sufficient to satisfy its capital expenditure requirements, there is a risk that debt or equity financing will be unavailable to meet these requirements or, if available, will be on terms unacceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects and also negatively impact the market price of the Common Shares.

Variations in Foreign Exchange Rates and Interest Rates: World oil and gas prices are quoted in United States dollars and are therefore affected by exchange rates, which will fluctuate over time. Material increases in the value of the United States dollar will negatively impact the Corporation's production revenues. Future exchange rates could accordingly impact the future value of the Corporation's reserves and resources as determined by independent evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there will be a credit risk associated with counterparties of the Corporation. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service any debt that it may incur, which could negatively impact the market price of the Common Shares.

Issuance of Debt: From time to time, the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may create debt or increase the Corporation's then-existing debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. The level of the indebtedness that the Corporation may have from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Common Share Price Volatility: The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Corporation's control, including the following:

- Actual or anticipated fluctuations in the Corporation's results of operations;
- Recommendations by securities research analysts;
- Changes in the economic performance or market valuations of other companies that investors deem comparable to the Corporation;
- The loss of executive officers and other key personnel of the Corporation;
- Sales or perceived sales of additional Common Shares;
- Significant acquisitions or business combinations, strategic partnerships, joint ventures or capital;
- Commitments by or involving the Corporation or its competitors; and
- Trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's business segments or target markets.

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information is prepared as at March 30, 2018.

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERCE in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The report by ERCE is dated February 21, 2018 (the "ERCE Report").

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The report by McDaniel is dated February 22, 2018 (the "McDaniel Report").

See "**Reserves and Resource Advisory**" above.

The information on reserves, contingent resources, prospective resources and estimates of future net revenue is presented below as follows:

(a) IPC's oil and gas assets in France, Malaysia and the Netherlands (summarized from the ERCE Report);
(b) IPC's oil and gas assets in Canada (summarized from the McDaniel Report); and
(c) Aggregation of IPC's oil and gas assets in Canada, France, Malaysia and the Netherlands.

IPC has generated aggregated tables which are the arithmetic sum of the two sets of results to arrive at combined IPC reserve and resource estimates with a reference date of December 31, 2017, even though the acquisition of the Suffield area assets in Canada did not complete until January 5, 2018.

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

The Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor (ERCE), the Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor (McDaniel) and Form 51-101F3 Report of Management are attached to this AIF as Schedules A, B and C.

IPC's Oil and Gas Assets in France, Malaysia and the Netherlands

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (International)

		France	Netherlands	Malaysia	Sub Total IPC International
Proved Developed Producing (PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	6.40	0.02	3.24	9.66
	net	5.61	0.02	2.79	8.42
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	5.21	-	5.21
	net	-	5.21	-	5.21
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	6.40	0.89	3.24	10.53
	net	5.61	0.89	2.79	9.28
Proved Developed Non Producing (PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.19	0.00	-	0.19
	net	0.16	0.00	-	0.16
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.57	-	0.57
	net	-	0.57	-	0.57
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	0.19	0.10	-	0.29
	net	0.16	0.10	-	0.26
Proved Undeveloped (PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	2.23	0.00	0.66	2.90
	net	1.91	0.00	0.57	2.48
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.05	-	0.05
	net	-	0.05	-	0.05
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	2.23	0.01	0.66	2.90
	net	1.91	0.01	0.57	2.49
Total Proved (1P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.82	0.02	3.91	12.75
	net	7.68	0.02	3.36	11.06
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	5.83	-	5.83
	net	-	5.83	-	5.83
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	8.82	0.99	3.91	13.72
	net	7.68	0.99	3.36	12.03

Proved plus Probable Reserves (International)

		France	Netherlands	Malaysia	Sub Total IPC International
Proved plus Probable Developed Producing (2PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	13.15	0.03	7.65	**20.83**
	net	11.60	0.03	6.55	**18.19**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	9.55	-	**9.55**
	net	-	9.55	-	**9.55**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	13.15	1.62	7.65	**22.42**
	net	11.60	1.62	6.55	**19.78**
Proved plus Probable Developed Non Producing (2PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.52	0.00	-	**0.52**
	net	0.44	0.00	-	**0.45**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	1.21	-	**1.21**
	net	-	1.21	-	**1.21**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	0.52	0.20	-	**0.72**
	net	0.44	0.20	-	**0.65**
Proved plus Probable Undeveloped (2PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	3.94	0.00	1.41	**5.35**
	net	3.38	0.00	1.22	**4.60**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	0.06	-	**0.06**
	net	-	0.06	-	**0.06**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	3.94	0.01	1.41	**5.36**
	net	3.38	0.01	1.22	**4.61**
Total Probable (PB) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.79	0.02	5.15	**13.96**
	net	7.75	0.02	4.41	**12.17**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	4.99	-	**4.99**
	net	-	4.99	-	**4.99**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	8.79	0.85	5.15	**14.79**
	net	7.75	0.85	4.41	**13.01**
Total Proved plus Probable (2P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	17.61	0.04	9.06	**26.70**
	net	15.43	0.04	7.77	**23.24**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Conventional Natural Gas (Bscf)	gross	-	10.82	-	**10.82**
	net	-	10.82	-	**10.82**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**
	net	-	-	-	**-**
Total Oil Equivalent (MMboe)	gross	17.61	1.84	9.06	**28.51**
	net	15.43	1.84	7.77	**25.04**

Proved plus Probable plus Possible Reserves (International)

		France	Netherlands	Malaysia	Sub Total IPC International
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	20.56	0.05	9.78	30.39
	net	18.19	0.05	8.38	26.62
Heavy Crude Oil (MMbbl)	gross				-
	net				-
Conventional Natural Gas (Bscf)	gross		15.87		15.87
	net		15.87		15.87
Natural Gas Liquids (MMbbl)	gross				-
	net				-
Total Oil Equivalent (MMboe)	gross	20.56	2.70	9.78	33.04
	net	18.19	2.70	8.38	29.26
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	0.59	0.00	-	0.60
	net	0.51	0.00	-	0.52
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	1.88	-	1.88
	net	-	1.88	-	1.88
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	0.59	0.32	-	0.91
	net	0.51	0.32	-	0.83
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	4.74	0.00	1.99	6.73
	net	4.05	0.00	1.67	5.72
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	0.12	-	0.12
	net	-	0.12	-	0.12
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	4.74	0.02	1.99	6.75
	net	4.05	0.02	1.67	5.74
Total Possible (PS) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	8.29	0.02	2.71	11.02
	net	7.32	0.02	2.28	9.62
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	7.05	-	7.05
	net	-	7.05	-	7.05
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	8.29	1.20	2.71	12.20
	net	7.32	1.20	2.28	10.79
Total Proved plus Probable plus Possible (3P) Reserves					
Light & Medium Crude Oil (MMbbl)	gross	25.89	0.06	11.77	37.72
	net	22.75	0.06	10.04	32.85
Heavy Crude Oil (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Conventional Natural Gas (Bscf)	gross	-	17.87	-	17.87
	net	-	17.87	-	17.87
Natural Gas Liquids (MMbbl)	gross	-	-	-	-
	net	-	-	-	-
Total Oil Equivalent (MMboe)	gross	25.89	3.04	11.77	40.70
	net	22.75	3.04	10.04	35.83

Net Present Value of Future Net Revenue – Proved Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved Developed Producing (PDP) Reserves													
France	93.2	91.7	86.6	82.7	72.8	63.9	60.2	68.5	67.4	65.6	59.7	53.7	14.74
Netherlands	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-3.21
Malaysia	120.7	114.9	111.7	109.7	105.1	100.9	120.7	114.9	111.7	109.7	105.1	100.9	39.33
Subtotal IPC International	**190.1**	**196.4**	**193.0**	**189.5**	**179.1**	**168.5**	**157.2**	**173.3**	**173.8**	**172.5**	**166.1**	**158.3**	**20.42**
Proved Developed Non Producing (PDNP) Reserves													
France	1.7	0.9	0.6	0.4	0.1	-0.1	1.3	0.7	0.4	0.3	0.0	-0.1	2.67
Netherlands	0.7	1.6	1.8	1.9	1.9	1.8	0.7	1.6	1.8	1.9	1.9	1.8	19.22
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**2.4**	**2.5**	**2.4**	**2.3**	**2.0**	**1.7**	**2.0**	**2.3**	**2.2**	**2.2**	**1.9**	**1.6**	**8.84**
Proved Undeveloped (PUD) Reserves													
France	66.1	33.8	22.2	16.5	6.7	1.0	48.8	24.6	15.8	11.4	3.8	-0.7	8.61
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	30.09
Malaysia	32.3	30.3	29.2	28.6	27.0	25.6	32.3	30.3	29.2	28.6	27.0	25.6	50.18
Subtotal IPC International	**98.6**	**64.3**	**51.7**	**45.3**	**33.9**	**26.8**	**81.3**	**55.2**	**45.3**	**40.2**	**31.0**	**25.1**	**18.18**
Total Proved (1P) Reserves													
France	161.0	126.4	109.4	99.6	79.6	64.8	110.3	93.8	83.6	77.3	63.5	52.8	12.96
Netherlands	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-0.75
Malaysia	153.0	145.2	140.9	138.3	132.1	126.5	153.0	145.2	140.9	138.3	132.1	126.5	41.16
Subtotal IPC International	**291.2**	**263.3**	**247.1**	**237.1**	**215.1**	**197.0**	**240.5**	**230.7**	**221.3**	**214.8**	**199.0**	**185.0**	**19.70**

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved plus Probable Developed Producing (2PDP) Reserves													
France	333.3	235.6	194.9	173.7	135.4	110.4	230.9	177.8	150.4	135.5	107.7	89.1	14.97
Netherlands	-6.1	8.6	12.6	14.3	16.5	17.0	-7.5	7.3	11.4	12.4	15.3	15.9	8.81
Malaysia	305.9	274.1	258.0	248.3	227.1	209.4	305.9	274.1	258.0	248.3	227.1	209.4	37.90
Subtotal IPC International	**633.1**	**518.3**	**465.5**	**436.4**	**379.0**	**336.9**	**529.4**	**459.1**	**419.7**	**396.2**	**350.1**	**314.5**	**22.06**
Proved plus Probable Developed Non Producing (2PDNP) Reserves													
France	4.0	4.1	3.1	2.5	1.5	0.9	2.4	3.2	2.5	2.0	1.1	0.6	5.74
Netherlands	3.3	4.2	4.2	4.0	3.5	3.0	2.5	3.5	3.5	3.4	2.9	2.5	19.62
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**7.2**	**8.3**	**7.3**	**6.6**	**5.0**	**3.9**	**4.9**	**6.8**	**6.0**	**5.4**	**4.0**	**3.1**	**10.13**
Proved plus Probable Undeveloped (2PUD) Reserves													
France	137.4	82.6	62.1	51.7	33.2	21.3	101.0	60.2	44.6	36.7	22.5	13.3	15.29
Netherlands	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.8	0.1	0.1	19.70
Malaysia	85.5	76.9	72.6	70.0	64.3	59.5	85.5	76.9	72.6	70.0	64.3	59.5	57.58
Subtotal IPC International	**223.2**	**159.7**	**134.9**	**121.9**	**97.7**	**81.0**	**186.6**	**137.3**	**117.3**	**107.4**	**86.8**	**72.9**	**26.45**
Total Probable (PB) Reserves													
France	313.7	195.9	150.8	128.5	90.5	67.8	224.0	147.3	113.8	96.9	67.7	50.3	16.58
Netherlands	20.2	21.4	20.2	19.3	16.8	14.5	18.0	19.3	18.2	17.3	14.9	12.8	22.72
Malaysia	238.5	205.8	189.7	180.0	159.3	142.4	238.5	205.8	189.7	180.0	159.3	142.4	40.84
Subtotal IPC International	**572.4**	**423.1**	**360.7**	**327.8**	**266.6**	**224.7**	**480.4**	**372.4**	**321.7**	**294.2**	**241.9**	**205.4**	**25.20**
Total Proved plus Probable (2P) Reserves													
France	474.7	322.3	260.1	228.0	170.1	132.6	334.3	241.2	197.4	174.1	131.3	103.1	14.78
Netherlands	-2.6	13.0	17.0	18.5	20.2	20.2	-4.8	11.0	15.0	16.6	18.3	18.5	10.08
Malaysia	391.4	351.0	330.6	318.3	291.4	268.9	391.4	351.0	330.6	318.3	291.4	268.9	40.98
Subtotal IPC International	**863.5**	**686.4**	**607.8**	**564.9**	**481.6**	**421.7**	**720.9**	**603.1**	**543.0**	**509.0**	**441.0**	**390.5**	**22.56**

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (International)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	BTAX NPV10
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves													
France	818.8	432.2	323.8	275.5	199.5	156.4	584.6	324.1	246.3	211.1	155.1	123.1	15.15
Netherlands	32.0	35.0	34.7	34.0	31.8	29.3	22.3	27.4	27.9	27.8	26.2	24.4	12.61
Malaysia	440.3	386.1	359.4	343.5	309.4	281.6	440.3	386.1	359.4	343.5	309.4	281.6	41.01
Subtotal IPC International	**1'291.1**	**853.3**	**717.9**	**653.1**	**540.7**	**467.3**	**1'047.3**	**737.6**	**633.6**	**582.5**	**490.8**	**429.1**	**22.32**
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves													
France	16.7	7.1	4.8	3.9	2.4	1.6	12.4	5.3	3.5	2.8	1.7	1.1	7.51
Netherlands	8.1	7.3	6.4	5.9	4.6	3.7	6.8	6.1	5.3	4.8	3.7	2.9	18.55
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**24.8**	**14.5**	**11.3**	**9.7**	**7.0**	**5.3**	**19.1**	**11.3**	**8.8**	**7.6**	**5.4**	**4.0**	**11.72**
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves													
France	191.7	115.2	87.3	73.3	48.8	33.4	140.7	83.4	62.3	51.7	33.1	21.4	18.09
Netherlands	0.7	0.7	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.4	0.4	30.40
Malaysia	117.8	104.9	98.4	94.6	86.2	79.3	96.6	87.3	82.6	79.8	73.7	68.5	56.79
Subtotal IPC International	**310.1**	**220.8**	**186.4**	**168.6**	**135.6**	**113.3**	**237.7**	**171.1**	**145.4**	**131.8**	**107.1**	**90.3**	**29.37**
Total Possible (PS) Reserves													
France	552.5	232.2	155.8	124.7	80.6	58.8	403.4	171.5	114.7	91.5	58.6	42.5	17.03
Netherlands	43.4	30.0	24.8	22.0	16.9	13.4	34.4	23.0	18.6	16.3	12.0	9.2	18.37
Malaysia	166.6	140.0	127.2	119.8	104.2	92.0	145.4	122.4	111.5	105.1	91.7	81.2	52.67
Subtotal IPC International	**762.5**	**402.2**	**307.8**	**266.5**	**201.7**	**164.2**	**583.2**	**316.9**	**244.8**	**212.9**	**162.3**	**132.9**	**24.69**
Total Proved plus Probable plus Possible (3P) Reserves													
France	1'027.1	554.5	415.9	352.7	250.7	191.4	737.7	412.7	312.2	265.7	189.9	145.6	15.50
Netherlands	40.8	43.0	41.8	40.6	37.0	33.6	29.6	33.9	33.6	32.9	30.3	27.6	13.35
Malaysia	558.0	491.0	457.8	438.1	395.6	360.9	536.8	473.4	442.1	423.4	383.1	350.1	43.63
Subtotal IPC International	**1'626.0**	**1'088.5**	**915.5**	**831.4**	**683.4**	**585.9**	**1'304.1**	**920.1**	**787.8**	**721.9**	**603.3**	**523.3**	**23.20**

Elements of Future Net Revenue (International)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	693.8	86.1	335.3	32.4	78.9	161.0	50.7	110.3
Netherlands	48.5	-	27.9	0.9	42.4	- 22.8	-	- 22.8
Malaysia	449.5	26.9	236.2	8.9	24.5	153.0	-	153.0
Subtotal IPC International	**1'191.8**	**113.1**	**599.5**	**42.2**	**145.8**	**291.2**	**50.7**	**240.5**

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	1'560.1	181.6	743.1	51.4	109.4	474.7	140.4	334.3
Netherlands	88.9	-	44.7	0.9	45.8	- 2.6	2.2	- 4.8
Malaysia	875.8	66.2	381.3	8.9	27.9	391.4	-	391.4
Subtotal IPC International	**2'524.8**	**247.8**	**1'169.1**	**61.2**	**183.1**	**863.5**	**142.6**	**720.9**

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	2'428.8	275.2	943.0	57.1	126.4	1'027.1	289.4	737.7
Netherlands	147.4	-	65.4	0.9	40.2	40.8	11.3	29.6
Malaysia	1'084.2	86.5	402.8	8.9	27.9	558.0	21.2	536.8
Subtotal IPC International	**3'660.4**	**361.7**	**1'411.3**	**66.9**	**194.5**	**1'626.0**	**321.9**	**1'304.1**

Net Present Value by Product Type (International)

IPC International Future Net Revenue BTAX at 10% Discount	Primary Product Type Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	237.8	-	- 0.7	-	237.1
Total Proved and Probable (2P) Reserves	546.3	-	18.5	-	564.9
Total Proved and Probable and Possible (3P) Reserves	790.8	-	40.6	-	831.4

IPC International USD per boe by product type	Primary Product Type Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/net boe)
Total Proved (1P) Reserves	21.54	-	- 0.12	-	19.70
Total Proved and Probable (2P) Reserves	23.55	-	1.68	-	22.56
Total Proved and Probable and Possible (3P) Reserves	24.11	-	2.22	-	23.20

Notes:
(1) Light Medium and Heavy Oil Future Net Revenue and Unit Value include associated gas
(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (International)

	Reference Prices					
	Brent	WTI	WCS	NBP	AECO	Empress
	Light & Medium Oil	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	Conventional Natural Gas	Conventional Natural Gas
Year	*USD/bbl*	*USD/bbl*	*CAD/bbl*	*USD/mmbtu*	*CAD/mmbtu*	*CAD/mmbtu*
2017	*54.35*	*50.87*	*49.70*	*n/a*	2.40	
2018	63.50	58.50	51.90	6.25	2.25	2.70
2019	61.30	58.70	57.00	6.37	2.65	2.95
2020	63.40	62.40	61.40	6.63	3.05	3.21
2021	70.10	69.00	66.00	7.00	3.40	3.56
2022	74.20	73.10	67.90	7.32	3.60	3.76
2023	75.60	74.50	69.20	7.44	3.65	3.82
2024	77.10	76.00	70.60	7.61	3.75	3.92
2025	78.60	77.50	72.00	7.73	3.80	3.97
2026	80.30	79.10	73.50	7.91	3.90	4.08
2027	81.90	80.70	74.90	8.03	3.95	4.13
2028	83.50	82.30	76.40	8.21	4.05	4.23
2029	85.10	83.90	77.90	8.39	4.15	4.34
2030	86.90	85.60	79.50	8.57	4.25	4.44
2031	88.60	87.30	81.10	8.70	4.30	4.49
2032	90.40	89.10	82.70	8.89	4.35	4.55
2033+	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

	Field Prices						
	Canada		France		Netherlands		Malaysia
		Conventional Natural Gas	Light & Medium Oil	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	Light & Medium Oil
Year	*USD/bbl (2)*	*USD/mcf (2)*	*USD/bbl (4)*	*USD/bbl (4)*	*USD/bbl*	*USD/mcf*	*USD/bbl (4)*
2017	*n/a*	*n/a*	*50.98*	*53.44*	*43.57*	*5.62*	*57.30*
2018	34.09	1.98	63.25	62.07	63.50	6.09	66.50
2019	38.05	2.18	61.05	59.87	61.30	6.23	64.30
2020	41.91	2.40	63.15	61.97	63.40	6.51	66.40
2021	46.87	2.77	69.85	68.67	70.10	6.89	73.10
2022	49.75	3.02	73.95	72.77	74.20	7.22	77.20
2023	50.70	3.06	75.35	74.17	75.60	7.35	78.60
2024	51.73	3.14	76.85	75.67	77.10	7.51	80.10
2025	52.75	3.19	78.35	77.17	78.60	7.64	81.60
2026	53.85	3.27	80.05	78.87	80.30	7.73	83.30
2027	54.87	3.31	81.65	80.47	81.90	7.84	84.90
2028	55.97	3.40	83.25	82.07	83.50	8.46	86.50
2029	57.07	3.48	84.85	83.67	85.10	8.66	88.10
2030	58.24	3.57	86.65	85.47	86.90	8.86	89.90
2031	59.42	3.61	88.35	87.17	88.60	9.01	91.60
2032	60.59	3.65	90.15	88.97	90.40	9.21	93.40
2033+	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

(1) Brent, WTI, WCS, and NBP reference prices are taken from McDaniel and Associates January 1, 2018. Price forecast inflated 2%/yr from 2033 onwards
(2) Field reference prices are calculated by McDaniel and Associates and are net of transportation and crude quality adjustments
(3) Netherlands gas prices are based upon the McDaniel NBP gas price forecast and on a field by field basis are calorific value dependent.
(4) The France and Malaysia price forecasts are derived by applying differentials to the reference McDaniel

Exchange rate Assumptions

Rate	2018	2019	2020	2021	2022 on
EUR/USD	0.87	0.87	0.87	0.87	0.87
GBP/USD	0.77	0.77	0.77	0.77	0.77
MYR/USD	4.25	4.25	4.25	4.25	4.25
CAD/USD	1.27	1.27	1.25	1.21	1.18

Reconciliation of Changes in Reserves (International)

	Malaysia	France	Netherlands	**Total**
Reconciliation of Proved Reserves Mmboe	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	**Oil Equivalent**
Opening Balance December 31, 2016	4.9	11.3	0.9	**17.0**
extensions and improved recovery	+ 0.7	+ 0.0	+ 0.0	**+ 0.7**
technical revisions	+ 0.8	- 0.5	+ 0.5	**+ 0.8**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	+ 0.0	- 1.1	+ 0.0	**- 1.1**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	3.9	8.8	1.0	**13.7**

	Malaysia	France	Netherlands	**Total**
Reconciliation of Proved + Probable Reserves Mmboe	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	**Oil Equivalent**
Opening Balance December 31, 2016	9.5	18.0	1.8	**29.4**
extensions and improved recovery	+ 1.4	+ 0.5	+ 0.0	**+ 1.9**
technical revisions	+ 0.8	+ 0.3	+ 0.4	**+ 1.6**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	- 0.3	- 0.3	+ 0.0	**- 0.6**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	9.1	17.6	1.8	**28.5**

	Malaysia	France	Netherlands	**Total**
Reconciliation of Proved + Probable + Possible Reserves Mmboe	Light & Medium Oil	Light & Medium Oil	Conventional Natural Gas	**Oil Equivalent**
Opening Balance December 31, 2016	13.3	23.8	3.2	**40.3**
extensions and improved recovery	+ 2.0	+ 0.7	+ 0.0	**+ 2.7**
technical revisions	- 1.1	+ 2.3	+ 0.3	**+ 1.5**
discoveries				**+ 0.0**
acquisitions				**+ 0.0**
dispositions				**+ 0.0**
economic factors	+ 0.0	- 0.0	+ 0.0	**- 0.0**
production	- 2.4	- 0.9	- 0.4	**- 3.7**
Closing Balance December 31, 2017	11.8	25.9	3.0	**40.7**

Undeveloped Reserves (International)

Undeveloped Reserves - International Assets
Volumes first attributed by year
Company Gross Basis

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.1	-	-	-	3.1
December 31, 2017	0.7	-	-	-	0.7
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.3	-	-	-	3.3
December 31, 2017	1.4	-	-	-	1.4

France / Malaysia Development Projects

	Light & Medium Crude Oil Reserves	Heavy Crude Oil Reserves	Conventional Natural Gas Resrves	Future Project Development Capital (MUSD)				Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe	ATAX NPV10 per boe
France - Vert La Gravelle Redevelopment	MMbbl gross	MMbbl gross	Bscf Gross	2018	2019	Total	USD per boe	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	USD per boe	USD per boe
Proved Undeveloped (PUD)	2.2	-	-	0.9	24.8	25.8	11.5	66	34	22	16	7	1	49	25	16	11	4	1	7.37	5.10
Proved and Probable Undeveloped (PPUD)	3.9	-	-	0.9	39.1	44.3	11.2	137	83	62	52	33	21	101	60	45	37	22	13	13.13	9.30
Proved plus Probable plus Possible Undeveloped (PPPUD)	4.7	-	-	0.9	39.1	49.8	10.5	192	115	87	73	49	33	141	83	62	52	33	21	15.47	10.90
Malaysia - A16 and A17 Development Wells																					
Proved Undeveloped (PUD)	0.7	-	-	7.7	-	7.7	11.7	32	30	29	29	27	26	32	30	29	29	27	26	43.15	43.15
Proved and Probable Undeveloped (PPUD)	1.4	-	-	7.7	-	7.7	5.5	85	77	73	70	64	59	85	77	73	70	64	59	49.52	49.52
Proved plus Probable plus Possible Undeveloped (PPPUD)	2.0	-	-	7.7	-	7.7	3.9	118	105	98	95	86	79	97	87	83	80	74	68	47.50	40.10
Subtotal France / Malaysia																					
Proved Undeveloped (PUD)	**2.9**	**-**	**-**	**8.7**	**24.8**	**33.5**	**11.6**	**98**	**64**	**51**	**45**	**34**	**27**	**81**	**55**	**45**	**40**	**31**	**25**	**15.55**	**13.80**
Proved and Probable Undeveloped (PPUD)	**5.4**	**-**	**-**	**8.7**	**39.1**	**52.0**	**9.7**	**223**	**159**	**135**	**122**	**97**	**81**	**186**	**137**	**117**	**107**	**87**	**73**	**22.73**	**19.92**
Proved plus Probable plus Possible Undeveloped (PPPUD)	**6.7**	**-**	**-**	**8.7**	**39.1**	**57.5**	**8.5**	**309**	**220**	**186**	**168**	**135**	**113**	**237**	**171**	**145**	**132**	**107**	**90**	**24.94**	**19.54**

IPC has proven, probable, and possible undeveloped reserves attributed to two projects: the drilling of the A16 and A17 development wells in Malaysia and the redevelopment of the Vert La Gravelle field in France.

Undeveloped Reserves are attributed in accordance with engineering and geological practices as defined under NI 51-101.

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 90% probability of being recovered.

Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 50% probability of being recovered.

Possible undeveloped reserves are those reserves that are less certain to be recovered than probable reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves have a 10% probability of being recovered.

See also “**Reserves and Resource Advisory**” above.

The pace of development of proven undeveloped reserves will be influenced by many factors, including but not limited to, the outcomes of yearly drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, regulatory changes and impact of future acquisitions and dispositions.

In general, development of probable undeveloped reserves requires additional evaluation data to increase the probability of success to an acceptable level for the Corporation. This increases the timeline for the development of these reserves. This timetable may be altered depending on outside market forces, changes in capital allocations and impact of future acquisitions and dispositions.

Malaysia

A two well infill campaign was sanctioned in 2017 and began during the fourth quarter of 2017. The project was well progressed at December 31, 2017 but not to the extent that the reserves attributed to the project could be classed as developed. The project has been completed and the infill wells were brought on stream in mid-January (A16) and mid-February (A17).

Additional development and exploration potential has been identified in the field which is discussed further in the Contingent and Prospective Resources sections.

France

IPC has plans for a five-well drilling campaign in the 100%-operated Vert La Gravelle field in the Paris Basin. This is a continuation of a programme that was halted in 2015 as a result of the changing economic climate. The facility and flow line work is complete and the remaining project scope covers drilling and completing the new production and injection wells. This project is considered in the undeveloped reserves base and is projected to start execution in 2019.

Infrastructure investments in the short term will include a maintenance program in the central part of the Villeperdue field and a provision for future pipeline work in the Les Arbousiers field in the Aquitaine Basin.

Significant Factors or Uncertainties Affecting Reserves Data (International)

In Malaysia, the main uncertainties relate to reservoir performance in particular rate of water-cut build for the recent wells A15, A16, and A17. This uncertainty has been captured in the 1P to 3P range of estimates. Other uncertainties include, but are not limited to, facility uptime performance, electric submersible pump performance and run life, and operating cost performance. There are no material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group's realized prices.

In France, the main uncertainties relate to reservoir performance in the Triassic formation pools that are early in their water-flood life. This uncertainty has been captured in the 1P to 3P range of estimates. The performance of the future development at Vert La Gravelle is also an uncertainty considered in the estimates. There are no material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group's realized prices.In addition, the French government enacted legislation in 2017 to restrict production of oil and gas under existing production licenses in France from 2040. The reported proved reserves assume a cessation of production as at 2040, although given the uncertainties regarding the application of this new legislation, the reported probable and possible reserves do not assume cessation at such date.

In the Netherlands, the main uncertainties in the reserves data relate to reservoir and operating cost performance. There are five licenses in the Netherlands with no reserves attributed but with abandonment liability. The following table contains management estimates of the value of the liability. There are no other material abandonment and reclamation costs other than what has been considered in the reserves assessment, high expected development or operating costs, or contractual obligations that would impair the Group's realized prices.

Abandonment Liability Estimates	After Deducting Income Tax, Discounted at:					
	0% (MUSD)	5% (MUSD)	8% (MUSD)	10% (MUSD)	15% (MUSD)	20% (MUSD)
Onshore						
Oosterend	0.5	0.5	0.5	0.5	0.4	0.4
Offshore						
F15a	1.2	0.9	0.8	0.7	0.6	0.5
F15b	0.8	0.6	0.6	0.5	0.4	0.3
F3UG	0.0	0.0	0.0	0.0	0.0	0.0
L7	12.3	9.7	8.4	7.6	6.1	4.9
Subtotal Offshore	**14.3**	**11.2**	**9.7**	**8.9**	**7.1**	**5.7**
Netherlands Total	**14.8**	**11.7**	**10.2**	**9.3**	**7.5**	**6.1**

See also "**Reserves and Resource Advisory**" above.

Future Development Costs (International)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
France	5.1	26.2	1.1	-	-	-	32.4	**28.4**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	15.0	26.2	1.1	-	-	-	42.2	**38.0**
Total Proved Plus Probable								
France	5.3	40.7	5.4	-	-	-	51.4	**44.5**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	15.2	40.7	5.4	-	-	-	61.2	**54.1**

Expectations of Sources and Costs of Funding (International)

IPC's development program will be funded by a combination of internally generated cash flows, access to existing and future credit facilities and possible equity financings. There is no assurance that the Group will allocate funds to develop the reserves as represented in this AIF. The Group may choose to delay or cancel discretionary development projects depending on economic factors, strategy and priorities. Equally, the Group may choose to accelerate activity where possible should circumstances allow.

Cost of funding is not included in the future net revenue estimates. The cost of funding is not expected to make further development activity uneconomic.

Producing and Non-Producing Well Counts (International)

	Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross wells	Net wells	Gross wells	Net wells	Gross wells	Net wells	Gross wells	Net wells
Malaysia	11.0	8.3	-	-	-	-	-	-
France	118.0	111.3	6.0	6.0	-	-	-	-
Netherlands	3.0	0.0	-	-	96.0	5.0	-	-

Properties with No Attributed Reserves (International)

							Outstanding Work Commitments					
Country	Property	Operator	Working Interest	Location	Gross Area (ha)	Net Area (ha)	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount (MUSD)	Amount Planned in 2018 (MUSD) Towards Commitments	Amount Planned after 2018 (MUSD) Towards Commitments	End of Commitment Period
France	Est-Champagne	IPC	100%	Onshore	132	132	none	-	-	-	-	-
	Esthéria	IPC	100%	Onshore	4'300	4'300	none	-	-	-	-	-
	Pays du Saulnois	IPC	40.0%	Onshore	19'800	7'920	none	-	-	-	-	-
	Plivot	IPC	100%	Onshore	19'800	19'800	none	-	-	-	-	-
Netherlands	Follega	Vermilion	9.30%	Onshore	300	28	none	-	-	-	-	-
	Lemsterland	Vermilion	9.30%	Onshore	11'100	1'032	none	-	-	-	-	-
Malaysia	PM328	IPC	35.0%	Offshore	560'000	196'000	none	-	-	-	-	-
	SB303 GHA	IPC	55.0%	Offshore	3'000	1'650	none	-	-	-	-	-
	PM307 GHA	IPC	75.0%	Offshore	10'800	8'100	none	-	-	-	-	-

IPC's properties with no attributed reserves include four exploration licenses in France, two exploration licenses in the Netherlands, one exploration license in Malaysia, and two Gas Holding Areas (GHA) in Malaysia. None of these properties have significant abandonment and reclamation costs, unusually high expected development or operating costs, or contractual obligations that would impact the realized pricing.

The GHAs in Malaysia cover existing gas discoveries that would require transportation infrastructure to develop. The capital cost associated with such infrastructure could be high relative to the size of these potential future developments. The development could require a portion of the gas to be sold at domestic pricing.

Tax Horizon (International)

In Malaysia, the Corporation has a significant cost recovery balance of USD 332 million as of January 1, 2018 and Petroleum Income Tax loss carryforwards of USD 48 million as of January 1, 2018. In the Netherlands, the Corporation benefits from a corporate tax loss carryforward, which is non-field specific, of approximately EUR 140 million as of January 1, 2018. Management expects to utilize the benefits of these loss positions over the next several years and expects to pay insignificant taxes in Malaysia and the Netherlands over this period. IPC pays current taxes in France. In December 2017, legislation was approved in France to reduce income tax rates starting in 2019.

Costs Incurred (International)

2017 costs incurred MUSD	Property Acquisition Costs Proved Properties	Property Acquisition Costs UnProved Properties	Exploration Costs	Appraisal Costs	Development Costs
France	-	-	0.0	4.2	4.6
Malaysia	-	-	0.2	- 0.3	11.7
Netherlands	-	-	0.8	-	1.8
Total	-	-	1.0	3.9	18.1

Exploration and Development Activities (International)

Exploration Activity Summary	France		Netherlands		Malaysia	
	gross	net	gross	net	gross	net
wells completed	-	-	1.0	0.0	-	-
completed as						
oil well	-	-	-	-	-	-
gas well	-	-	-	-	-	-
service well	-	-	-	-	-	-
stratigraphic test well	-	-	-	-	-	-
dry hole	-	-	1.0	0.0	-	-

Development Activity Summary	France		Netherlands		Malaysia	
	gross	net	gross	net	gross	net
wells completed	-	-	1.0	0.1	-	-
completed as						
oil well	-	-	-	-	-	-
gas well	-	-	1.0	0.1	-	-
service well	-	-	-	-	-	-
stratigraphic test well	-	-	-	-	-	-
dry hole	-	-	-	-	-	-

Production Forecast Estimates (International)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
France	1.96	-	-	-	1.96
Netherlands	0.02	-	0.79	-	0.80
Malaysia	5.29	-	-	-	5.29
Subtotal IPC International	**7.27**	**-**	**0.79**	**-**	**8.05**
Total Proved plus Probable (2P) Scenario					
France	2.31	-	-	-	2.31
Netherlands	0.02	-	0.94	-	0.96
Malaysia	6.58	-	-	-	6.58
Subtotal IPC International	**8.92**	**-**	**0.94**	**-**	**9.86**
Total Proved plus Probable plus Possible (3P) Scenario					
France	2.62	-	-	-	2.62
Netherlands	0.02	-	1.08	-	1.10
Malaysia	7.72	-	-	-	7.72
Subtotal IPC International	**10.36**	**-**	**1.08**	**-**	**11.44**

Production History (International)

France - Light and Medium Crude Oil	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mbopd	2.47	2.49	2.47	2.38	**2.44**
Unit Volume Average (USD/bbl)					
Prices received	78.41	38.22	46.28	54.89	**54.36**
Royalties Paid	2.70	2.81	3.04	6.46	**3.74**
Production Costs	39.56	16.63	19.18	27.24	**25.59**
Netback	36.15	18.78	24.06	21.19	**25.03**

Netherlands - Conventional Natural Gas	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, MMscf/d	8.68	6.58	6.86	6.24	**7.08**
Unit Volume Average (USD/bbl)					
Prices received	37.00	33.21	35.95	43.83	**37.38**
Royalties Paid	-	0.08	0.00	0.00	**0.02**
Production Costs	12.42	18.31	21.89	22.53	**18.33**
Netback	24.58	14.82	14.06	21.30	**19.03**

Malaysia - Light and Medium Crude Oil	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mbopd	7.59	6.99	5.65	6.53	**6.68**
Unit Volume Average (USD/bbl)					
Prices received	43.15	57.48	64.98	63.75	**56.61**
Royalties Paid	0.27	0.26	0.23	0.31	**0.27**
Production Costs	0.97	15.14	22.67	12.74	**12.19**
Netback	41.91	42.08	42.08	50.70	**44.15**

IPC Total - Oil Equivalent	Q1 '17	Q2'17	Q3'17	Q4'17	2017
Production, Mboepd	11.51	10.58	9.17	9.94	**10.31**
Unit Volume Average (USD/bbl)					
Prices received	50.32	50.17	56.52	59.68	**53.96**
Royalties Paid	0.76	0.84	0.94	1.75	**1.06**
Production Costs	10.69	15.82	21.66	17.23	**16.07**
Netback	38.87	33.51	33.92	40.70	**36.83**

Contingent Resources (International)

Working Interest Contingent Resources	Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
Malaysia						
Bertam Field	Development Drilling (2)	Established	Economic	Development Unclarified	Conceptual	75%
France Paris Basin						
Amaltheus	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Courdemanges	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Dommartin Lettree	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	43.01%
Genievre	Improved water injection	Established	not determined	Development Unclarified	Conceptual	100%
Grandville	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Merisier	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Soudron	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Vert La Gravelle	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
Villeperdue	Development Drilling, Improved Water Injection	Established	not determined	Development Unclarified	Conceptual	100%
Villeseneux	Development Drilling	Established	not determined	Development Unclarified	Conceptual	100%
France Aquitaine Basin						
Courbey	Development Drilling	Established	not determined	Development Unclarified	Conceptual	50%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe			Chance of Develop ment
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Malaysia													
Bertam Field	828	1'380	1'932	-	-	-	-	-	-	828	1'380	1'932	75%
France Paris Basin													
Amaltheus	202	719	1'245	-	-	-	-	-	-	202	719	1'245	50%
Courdemanges	428	1'558	2'651	-	-	-	-	-	-	428	1'558	2'651	50%
Dommartin Lettree	521	993	1'285	-	-	-	-	-	-	521	993	1'285	50%
Genievre	-	84	231	-	-	-	-	-	-	-	84	231	50%
Grandville	111	1'499	2'093	-	-	-	-	-	-	111	1'499	2'093	50%
Merisier	564	2'582	4'052	-	-	-	-	-	-	564	2'582	4'052	50%
Soudron	1'436	1'599	2'512	-	-	-	-	-	-	1'436	1'599	2'512	50%
Vert La Gravelle	-	104	1'010	-	-	-	-	-	-	-	104	1'010	50%
Villeperdue	2'272	4'188	4'710	-	-	-	-	-	-	2'272	4'188	4'710	50%
Villeseneux	204	512	605	-	-	-	-	-	-	204	512	605	50%
Paris Basin Subtotal Unrisked	5'738	13'838	20'393	-	-	-	-	-	-	5'738	13'838	20'393	
France Aquitaine Basin													
Courbey	1'300	2'150	3'700	-	-	-	-	-	-	1'300	2'150	3'700	50%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			**Total Oil Equivalent Mboe**		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	**1C**	**2C**	**3C**
Subtotal by Country Unrisked												
Malaysia	828	1'380	1'932	-	-	-	-	-	-	**828**	**1'380**	**1'932**
France	7'038	15'988	24'093							**7'038**	**15'988**	**24'093**
Total Unrisked	7'866	17'368	26'025	-	-	-	-	-	-	**7'866**	**17'368**	**26'025**
Subtotal by Country Risked by Chance of Developement												
Malaysia	621	1'035	1'449	-	-	-	-	-	-	**621**	**1'035**	**1'449**
France	3'519	7'994	12'047	-	-	-	-	-	-	**3'519**	**7'994**	**12'047**
Total Risked	4'140	9'029	13'496	-	-	-	-	-	-	**4'140**	**9'029**	**13'496**

Malaysia

The contingent resources in Malaysia relate to the drilling of two additional infill producers which are analogous in concept to the recently executed A16 and A17 infill wells. There are spare slots on the wellhead platform to accommodate the new wells so capital requirements relate to drilling, completion, and a minor amount for surface tie-in. No material facility modifications are required to accommodate the new wells. The estimated cost is between USD 30 and 40 million for the two well campaign.

The main contingencies relate to refinement of project definition and approval of the development concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2020 horizon. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. The total best estimate contingent resources attributed to oil drilling is 1.4 MMboe which is classed in economic sub-category. The uncertainty in this project is captured in the 1C and 3C resource range 0.8 to 1.9 MMboe. This project is considered to have a 0.75 chance of development.

A detailed development study and discounted cash flow evaluation specific to these two wells has not been undertaken, however an economic threshold sensitivity run by IPC and reviewed by ERCE is considered adequate to classify these resources as economic under economic conditions that are the same as those used for reporting reserves.

France

The contingent resource estimates reported for France relate to development drilling and water-flood optimization opportunities. In all cases, the product type is light crude oil. The risk and uncertainty associated with the contingent resources in France is largely due to limited seismic coverage and understanding of structural extent of the fields. To recover the contingent resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. In all cases, the contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

Prospective Resources (International)

Malaysia

Prospect	Working Interest	Gross Working Interest Light Crude Oil & Medium Crude Oil (Mbbl)			Chance of Commerciality	Risked Gross Working Interest Light Crude Oil & Medium Crude Oil (Mbbl)		
		Low	Mid	High		Low	Best	High
Bertam I-35	75%	2’025	5’400	11’775	20.2%	409	1’091	2’379
Bertam Extension	75%	180	435	1’035	35.0%	63	152	362

The prospective resources related to I-35 relate to a closure mapped in a horizon shallower than the Bertam K10.1 productive horizon. The target reservoir has been penetrated by several wells demonstrating reservoir quality however there are no clear indications of oil in the wells drilled to date. 3D seismic interpretation suggests a closure up-dip of the drilled wells indicating the potential for a hydrocarbon accumulation. Charge and closure are the two main risks with the chance of geologic success estimated at 20.2%. The prospect is in a location that could potentially be developed across the FPSO Bertam. Positive factors include the potential for a stratigraphic trapping mechanism resulting in volumes towards the high end of the estimated range. Negative factors include exploration risk and the risk of high development costs. Chance of development in a discovery scenario is considered high. The product type is expected to be light crude oil.

The cost of development in a discovery scenario is estimated to be USD 50 to 100 million depending on production and injection well requirements and infrastructure modifications at the FPSO Bertam. The recovery technology would be either natural water drive or water-flood. Timing of an exploration well might be in the next 2 years resulting in first production in the next 2 to 5 years.

The Bertam extension prospective resources relate to a feature mapped on 3D seismic less than 1 km to the east of the Bertam K10.1 field limit. This feature is analogous to the productive A-15 area accumulation, which was drilled and put on production in 2016. The target reservoir has been drilled extensively in the nearby Bertam field so reservoir, seal, and source are relatively low risk. The main risks relate to oil water contact level and closure. The chance of success has been estimated at 35%. Chance of development in a discovery scenario is considered high. This prospect is within reach of the Bertam wellhead platform and production could be accommodated in the existing facilities. Positive factors include the potential for an oil water contact deeper than the Bertam field and higher than expected reservoir properties. Negative factors include the risk of finding a limited oil column to develop. The product type is expected to be light crude oil.

The cost of development in a discovery scenario is estimated to be USD 15 to 25 million depending on pilot well requirements. No major modifications to the FPSO would be required to accommodate production from this prospect. The recovery technology would be natural water drive. Timing of an exploration well might be in the next 1 to 2 years resulting in first production within months of drilling.

IPC's Oil and Gas Assets in Canada

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
Company Gross Working Interest Reserves	-	-	-	-
Company Net Reserves	-	-	-	-
Heavy Crude Oil (MMbbl)				
Company Gross Working Interest Reserves	13.1	0.3	5.4	18.9
Company Net Reserves	12.6	0.3	5.1	17.9
Conventional Natural Gas (Bscf)				
Company Gross Working Interest Reserves	331.2	26.1	0.6	357.8
Company Net Reserves	313.9	24.8	0.6	339.2
Natural Gas Liquids (MMbbl)				
Company Gross Working Interest Reserves	0.0	0.0	0.0	0.0
Company Net Reserves	0.0	0.0	0.0	0.0
Total Oil Equivalent (Mmboe)				
Company Gross Working Interest Reserves	68.3	4.7	5.6	78.6
Company Net Reserves	64.9	4.4	5.2	74.5

Proved plus Probable Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
Company Gross Working Interest Reserves	-	-	-	-	-
Company Net Reserves	-	-	-	-	-
Heavy Crude Oil (MMbbl)					
Company Gross Working Interest Reserves	17.4	0.3	9.6	8.4	27.3
Company Net Reserves	16.5	0.3	8.8	7.7	25.7
Conventional Natural Gas (Bscf)					
Company Gross Working Interest Reserves	379.3	58.7	1.1	81.3	439.1
Company Net Reserves	359.5	55.2	1.1	76.5	415.8
Natural Gas Liquids (MMbbl)					
Company Gross Working Interest Reserves	0.0	0.1	0.0	0.1	0.1
Company Net Reserves	0.0	0.0	0.0	0.0	0.1
Total Oil Equivalent (Mmboe)					
Company Gross Working Interest Reserves	80.6	10.2	9.8	22.1	100.6
Company Net Reserves	76.5	9.5	9.0	20.5	95.0

Proved plus Probable plus Possible Reserves (Canada)

Light & Medium Crude Oil (MMbbl)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
Company Gross Working Interest Reserves	-	-	-	-	-
Company Net Reserves	-	-	-	-	-
Heavy Crude Oil (MMbbl)					
Company Gross Working Interest Reserves	21.7	0.5	12.3	7.2	34.5
Company Net Reserves	20.5	0.4	11.1	6.3	32.0
Conventional Natural Gas (Bscf)					
Company Gross Working Interest Reserves	427.1	69.3	1.4	58.7	497.8
Company Net Reserves	404.8	65.2	1.3	55.6	471.4
Natural Gas Liquids (MMbbl)					
Company Gross Working Interest Reserves	0.0	0.1	0.0	0.0	0.1
Company Net Reserves	0.0	0.0	0.0	0.0	0.1
Total Oil Equivalent (Mmboe)					
Company Gross Working Interest Reserves	92.9	12.1	12.6	17.0	117.6
Company Net Reserves	87.9	11.3	11.3	15.6	110.6

Net Present Value of Future Net Revenue – Proved Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
0%	534.7	45.8	136.4	717.0
5%	519.6	31.5	69.4	620.5
8%	480.9	25.4	48.6	554.9
10%	454.1	22.1	38.8	515.0
15%	393.0	15.6	22.6	431.2
20%	343.2	11.0	13.0	367.1

Net Present Value After Tax (MUSD)	Proved Developed Producing	Proved Developed Non Producing	Proved Undeveloped	Total Proved
0%	419.3	34.3	117.0	570.6
5%	427.9	22.7	55.8	506.4
8%	399.9	17.8	37.4	455.1
10%	379.1	15.2	28.9	423.2
15%	330.0	10.1	15.2	355.2
20%	289.1	6.6	7.2	302.9

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
0%	761.3	115.1	295.7	455.1	1'172.1
5%	664.6	78.7	143.4	266.2	886.7
8%	593.7	63.5	101.2	203.5	758.4
10%	550.9	55.3	82.1	173.2	688.2
15%	461.9	39.6	51.1	121.4	552.5
20%	395.0	28.7	33.1	89.8	456.9

Net Present Value After Tax (MUSD)	Proved plus Probable Developed Producing	Proved plus Probable Developed Non Producing	Proved plus Probable Undeveloped	Total Probable	Total Proved plus Probable
0%	602.3	84.9	245.2	361.9	932.4
5%	542.8	56.6	110.7	203.8	710.2
8%	487.9	44.9	75.3	153.1	608.2
10%	453.9	38.7	59.6	129.0	552.2
15%	382.2	26.8	34.8	88.6	443.9
20%	327.9	18.8	20.8	64.6	367.4

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (Canada)

Net Present Value Before Tax (MUSD)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
0%	1'013.9	156.2	435.9	433.8	1'605.9
5%	791.6	107.7	205.0	217.6	1'104.3
8%	685.4	87.1	144.8	158.8	917.2
10%	626.6	75.9	117.9	132.2	820.4
15%	512.6	54.7	74.9	89.6	642.2
20%	431.6	40.0	50.2	65.0	521.9

Net Present Value After Tax (MUSD)	Proved plus Probable plus Possible Developed Producing	Proved plus Probable plus Possible Developed Non Producing	Proved plus Probable plus Possible Undeveloped	Total Possible	Total Proved plus Probable plus Possible
0%	811.9	114.1	344.0	337.5	1'270.0
5%	642.8	77.5	154.3	164.5	874.6
8%	558.5	62.0	106.2	118.6	726.7
10%	511.6	53.7	85.1	98.2	650.4
15%	420.1	37.8	51.9	65.9	509.8
20%	354.9	27.0	33.1	47.6	415.0

Elements of Future Net Revenue (Canada)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada	2'015.9	92.9	735.5	138.5	332.1	717.0	146.4	570.6

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Income Taxes
Canada	2'814.6	152.1	955.9	184.3	350.2	1'172.1	239.7	932.4

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada	3'502.8	219.0	1'137.9	184.3	355.8	1'605.9	335.9	1'270.0

Net Present Value by Product Type (Canada)

	Primary Product Type				
IPC Canada Future Net Revenue BTAX at 10% Discount	Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	-	236.6	278.5	-	515.0
Total Proved and Probable (2P) Reserves	-	340.6	347.6	-	688.2
Total Proved and Probable and Possible (3P) Reserves	-	429.3	391.1	-	820.4

	Primary Product Type				
IPC Canada USD per net boe by product type	Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/net boe)
Total Proved (1P) Reserves	-	13.20	0.83	-	6.91
Total Proved and Probable (2P) Reserves	-	13.27	0.84	-	7.24
Total Proved and Probable and Possible (3P) Reserves	-	13.43	0.84	-	7.42

Notes
(1) Light, Medium, and Heavy Oil Future Net Revenue and Unit Value include associated gas
(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (Canada)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Forecast Prices used in Estimates" above. The same forecast prices are used with respect to Canada.

Reconciliation of Changes in Reserves (Canada)

Reconciliation of Proved Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 18.9	+ 59.6	+ 0.0	**+ 78.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	18.9	59.6	0.0	**78.6**

Reconciliation of Proved + Probable Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 27.3	+ 73.2	+ 0.1	**+ 100.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	27.3	73.2	0.1	**100.6**

Reconciliation of Proved + Probable + Possible Reserves Mmboe	Heavy Oil	Convent-ional Natural Gas	Natural Gas Liquids	**Oil Equivalent**
Opening Balance December 31, 2016	-	-	-	**-**
extensions and improved recovery				**+ 0.0**
technical revisions				**+ 0.0**
discoveries				**+ 0.0**
acquisitions	+ 34.5	+ 83.0	+ 0.1	**+ 117.6**
dispositions				**+ 0.0**
economic factors				**+ 0.0**
production				**+ 0.0**
Closing Balance December 31, 2017	34.5	83.0	0.1	**117.6**

Undeveloped Reserves (Canada)

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	-	-	-	-	-
December 31, 2017	-	5.4	0.6	0.0	6.2
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	-	-	-	-	-
December 31, 2017	-	9.6	1.1	0.0	9.8

Development Projects (Canada)

	Light & Medium Crude Oil Reserves MMbbl gross	Heavy Crude Oil Reserves MMbbl gross	Convent-ional Natural Gas Reserves Bscf Gross	Future Project Development Capital MUSD				Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe USD per boe	ATAX NPV10 per boe USD per boe
Canada - Oil Drilling and EOR				2018	2019	Total	USD per boe	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%		
Proved Undeveloped (PUD)	-	5.4	0.6	4.1	16.4	43.1	7.8	142	70	49	39	23	13	117	56	37	29	15	7	7.03	5.21
Proved and Probable Undeveloped (PPUD)	-	9.6	1.1	4.1	22.8	65.6	6.7	296	143	101	82	51	33	245	111	75	60	35	21	8.37	6.08
Proved plus Probable plus Possible Undeveloped (PPPUD)	-	12.3	1.4	4.1	22.8	65.6	5.2	436	205	145	118	75	50	344	154	106	85	22	33	9.39	6.78

Development plans in Canada include development drilling in the glauconitic oil pools, expansion of alkaline-surfactant-polymer enhanced oil recovery to the glauconitic wash-over N2N pool, and optimization of the existing gas well stock.

The glauconitic development drilling consists of a combination of infill and step-out drilling of horizontal producers. The wells are generally 1000 metres dual leg horizontal producers although the length varies according to the reservoir and in cases single leg and triple leg producers are also considered. The wells are pumped with progressive cavity pumps and reservoir pressure is supported by natural bottom water drive supplemented by produced water re-injection.

Enhanced oil recovery expansion to the N2N pool entails commissioning already installed facilities, drilling producer and injector horizontal wells, and proceeding with injecting an alkaline-surfactant-polymer mix into the reservoir to mobilize oil that would not be recoverable with water-flooding alone. This method has been applied in the nearby and geologically analogous UU and YYY pools with positive reservoir response.

Optimization of existing well stock covers a range of activities including pulling of siphon strings, adding new completion intervals, and re-fracturing existing completions.

Significant Factors or Uncertainties Affecting Reserves Data (Canada)

In Canada, the main uncertainties relate to performance of future infill wells and the effectiveness of the alkaline-surfactant-polymer injection in mobilizing bypassed oil. These uncertainties are captured in the 1P to 3P range of estimates. Other uncertainties include weather related downtime and facility performance and effectiveness of gas optimization investments. The abandonment and reclamation liability beyond what has been considered in the reserve assessment is not material to the Canadian asset valuation. This asset does not have high expected development or operating cost, or contractual obligations that would impair the Group's realized prices.

See also "**Reserves and Resource Advisory**" above.

Future Development Costs (Canada)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
Canada	6.8	29.7	33.1	16.5	3.2	49.3	138.5	**86.4**
Total Proved Plus Probable								
Canada	6.8	36.0	39.0	18.2	14.8	69.3	184.3	**116.7**

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			**Total Oil Equivalent Mboe**		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	**1C**	**2C**	**3C**
Canada - Unrisked	-	-	-	5'462	7'373	9'954	185'385	231'732	289'665	**36'360**	**45'995**	**58'232**
Canada - risked	-	-	-	3'341	4'510	6'088	120'627	150'784	188'481	**23'446**	**29'641**	**37'502**

Expectations of Sources and Costs of Funding (Canada)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Expectations of Sources and Costs of Funding" above. The same disclosure applies with respect to Canada.

Producing and Non-Producing Well Counts (Canada)

	Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	550.0	550.0	393.0	393.0	10’252.0	10’226.8	527.0	527.0

Properties with No Attributed Reserves (Canada)

							Outstanding Work Commitments					
Country	Property	Operator	Working Interest	Location	Gross Area (ha)	Net Area (ha)	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount (MUSD)	Amount Planned in 2018 (MUSD) Towards Commitments	Amount Planned after 2018 (MUSD) Towards Commitments	End of Commitment Period
Canada	Suffield	IPC	100%	Onshore	3424	3424	expiry	Mannville	-	-	-	17 May 18
	Suffield	IPC	100%	Onshore	832	832	expiry	Bow Island and Mannville	-	-	-	3 Oct 18
	Suffield	IPC	100%	Onshore	64	64	expiry	Bow Island and Mannville	-	-	-	18 Dec 18
	Suffield	IPC	100%	Onshore	64	64	expiry	Bow Island and Mannville	-	-	-	4 Sep 19

Tax Horizon (Canada)

IPC expects to pay current taxes in Canada commencing in 2019 in respect of 2018 income.

Production Forecast Estimates (Canada)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
Canada	-	6.12	16.10	-	22.22
Total Proved plus Probable (2P) Scenario					
Canada	-	6.32	16.27	-	22.59
Total Proved plus Probable plus Possible (3P) Scenario					
Canada	-	6.41	16.38	-	22.79

Contingent Resources (Canada)

Working Interest Contingent Resources	Project Type	Technology	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
Canada						
Washover Pools						
P3P Pool	ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
D2D Pool	ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
M3M Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
F3F Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
O3O Pool	WF+ASP	Established	Sub-Economic	Development Unclarified	Conceptual	100%
Oil Development Drilling (117)						
Glauconitic	Development Drilling (76)	Established	Economic	Development Unclarified	Conceptual	100%
Glauconitic	Development Drilling (41)	Established	Sub-Economic	Development Unclarified	Conceptual	100%
Gas Development Drilling (2,540)						
Alderson	Development Drilling (470)	Established	Economic	Development Unclarified	Conceptual	100%
Suffield	Development Drilling (1,061)	Established	Economic	Development Unclarified	Conceptual	100%
Suffield	Development Drilling (1,009)	Established	Sub-Economic	Development Unclarified	Conceptual	100%

Working Interest Contingent Resources	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Conventional Natural Gas MMscf			Total Oil Equivalent Mboe			Chance of Develop ment
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Canada													
Washover Pools													
P3P Pool	-	-	-	498	672	908	-	-	-	498	672	908	50%
D2D Pool	-	-	-	372	502	678	-	-	-	372	502	678	50%
M3M Pool	-	-	-	351	474	639	-	-	-	351	474	639	50%
F3F Pool	-	-	-	131	176	236	-	-	-	131	176	236	50%
O3O Pool	-	-	-	191	258	349	-	-	-	191	258	349	50%
Subtotal Washover Pools	-	-	-	1543	2083	2812	-	-	-	1'543	2'083	2'812	
Oil Development Drilling (117)													
Glauconitic	-	-	-	3052	4'120	5562	-	-	-	3'052	4'120	5'562	70%
Glauconitic	-	-	-	867	1'170	1580	-	-	-	867	1'170	1'580	50%
Subtotal Oil Drilling	-	-	-	3919	5'290	7'142	-	-	-	3'919	5'290	7'142	
Gas Development Drilling (2,540)													
Alderson	-	-	-	-	-	-	36'284	45'355	56'694	6'047	7'559	9'449	70%
Suffield	-	-	-	-	-	-	103'389	129'237	161'546	17'232	21'540	26'924	70%
Suffield	-	-	-	-	-	-	45'712	57'140	71'425	7'619	9'523	11'904	50%
Subtotal Gas Drilling	-	-	-	-	-	-	185'385	231'732	289'665	30'898	38'622	48'278	
Canada Total Unrisked	-	-	-	5'462	7'373	9'954	185'385	231'732	289'665	36'360	45'995	58'231	

IPC has a 100% working interest in all of the contingent resources tabulated above. The oil contingent resources relate to heavy oil, and the gas contingent resources relate to conventional natural gas.

The contingent resources reported for Canada are consolidated into three project categories: shallow gas development drilling, oil development drilling and ASP expansion. In all cases the recovery of the resources would be via established technology, are based upon conceptual development plans, are classed in either sub-economic or economic category as discussed below, and in terms of project maturity are considered in all cases as having development unclarified status.

The shallow gas drilling project is estimated to require an estimated CAD 350 to 450 million with the main contingencies being natural gas prices, refinement of project definition, and approval of the project concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2025 horizon. It is likely that the project would be approved and implemented in a number of stages. The project is primarily drilling and completion scope with minimal infrastructure investment required. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include natural gas price risk as well as geologic and well completion risk. The total contingent resource attributed to shallow gas drilling is 38.6 MMboe with 9.5 MMboe considered sub-economic and 29.1 MMboe considered economic. The conventional natural gas contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

The oil development drilling is estimated by to require CAD 75 to 100 million of capital largely consisting of drilling and completion scope with minor facility and infrastructure investments. The main contingencies relate to refinement of project definition and approval of the development concept. Timing of first commercial production, should the project proceed, is expected to be in the 2019 to 2025 horizon. It is likely that the project would be approved and implemented in a number of stages. Positive factors include opportunity to reduce capital requirements and to improve per well production performance relative to forecast. Negative factors include crude oil price risk as well as geologic and reservoir performance risk. The total contingent resources attributed to oil drilling is 5.3 MMboe of which 4.1 MMboe is in economic category and 1.2 MMboe is in sub-economic category. The heavy oil development drilling contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

The ASP expansion and water-flood optimization projects are conceptually defined. The estimated capital to execute this project is CAD 40 to 80 million which is a combination of facility and pipeline expansion and drilling of injectors and producers. Timing of first commercial production, should the project proceed is expected to be in the 2022 to 2027 horizon. It is likely that the project would be approved and implemented in a number of stages. Positive factors include opportunity to reduce capital and operating cost requirements and to improve oil recovery efficiency relative to forecast. Negative factors include oil price risk, operating cost risk, geologic risk, and reservoir performance risk. The total contingent resource attributed to ASP expansion and water-flood optimization projects is 2.1 MMboe and is classed in sub-economic category. These enhanced oil recovery contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves. Implicit in project approval is the demonstration of economic development scheme to recover the resources.

Aggregation of IPC's oil and gas assets in Canada, France, Malaysia and the Netherlands

Oil and Gas Reserves – Based on Forecast Prices and Costs

Proved Reserves (Aggregated)

		France	Netherlands	Malaysia	IPC International	Canada	Total IPC
Proved Developed Producing (PDP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	6.40	0.02	3.24	9.66	-	9.66
	net	5.61	0.02	2.79	8.42	-	8.42
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	13.12	13.12
	net	-	-	-	-	12.59	12.59
Conventional Natural Gas (Bscf)	gross	-	5.21	-	5.21	331.16	336.37
	net	-	5.21	-	5.21	313.88	319.09
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	0.03
	net	-	-	-	-	0.02	0.02
Total Oil Equivalent (MMboe)	gross	6.40	0.89	3.24	10.53	68.34	78.86
	net	5.61	0.89	2.79	9.28	64.92	74.21
Proved Developed Non Producing (PDNP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	0.19	0.00	-	0.19	-	0.19
	net	0.16	0.00	-	0.16	-	0.16
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	0.32	0.32
	net	-	-	-	-	0.27	0.27
Conventional Natural Gas (Bscf)	gross	-	0.57	-	0.57	26.06	26.63
	net	-	0.57	-	0.57	24.75	25.33
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.00	0.00
	net	-	-	-	-	0.00	0.00
Total Oil Equivalent (MMboe)	gross	0.19	0.10	-	0.29	4.66	4.95
	net	0.16	0.10	-	0.26	4.40	4.66
Proved Undeveloped (PUD) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	2.23	0.00	0.66	2.90	-	2.90
	net	1.91	0.00	0.57	2.48	-	2.48
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	5.44	5.44
	net	-	-	-	-	5.06	5.06
Conventional Natural Gas (Bscf)	gross	-	0.05	-	0.05	0.62	0.67
	net	-	0.05	-	0.05	0.59	0.64
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.01	0.01
	net	-	-	-	-	0.01	0.01
Total Oil Equivalent (MMboe)	gross	2.23	0.01	0.66	2.90	5.56	8.46
	net	1.91	0.01	0.57	2.49	5.17	7.66
Total Proved (1P) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	8.82	0.02	3.91	12.75	-	12.75
	net	7.68	0.02	3.36	11.06	-	11.06
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	18.88	18.88
	net	-	-	-	-	17.93	17.93
Conventional Natural Gas (Bscf)	gross	-	5.83	-	5.83	357.84	363.67
	net	-	5.83	-	5.83	339.22	345.05
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	0.03
	net	-	-	-	-	0.02	0.02
Total Oil Equivalent (MMboe)	gross	8.82	0.99	3.91	13.72	78.56	92.28
	net	7.68	0.99	3.36	12.03	74.49	86.52

Proved plus Probable Reserves (Aggregated)

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Proved plus Probable Developed Producing (2PDP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	13.15	0.03	7.65	20.83	-	20.83
	net	11.60	0.03	6.55	18.19	-	18.19
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	17.39	17.39
	net	-	-	-	-	16.53	16.53
Conventional Natural Gas (Bscf)	gross	-	9.55	-	9.55	379.35	388.90
	net	-	9.55	-	9.55	359.55	369.09
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.03	0.03
	net	-	-	-	-	0.02	0.02
Total Oil Equivalent (MMboe)	gross	13.15	1.62	7.65	22.42	80.64	103.06
	net	11.60	1.62	6.55	19.78	76.48	96.26
Proved plus Probable Developed Non Producing (2PDNP) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	0.52	0.00	-	0.52	-	0.52
	net	0.44	0.00	-	0.45	-	0.45
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	0.33	0.33
	net	-	-	-	-	0.28	0.28
Conventional Natural Gas (Bscf)	gross	-	1.21	-	1.21	58.66	59.87
	net	-	1.21	-	1.21	55.15	56.36
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.06	0.06
	net	-	-	-	-	0.04	0.04
Total Oil Equivalent (MMboe)	gross	0.52	0.20	-	0.72	10.16	10.89
	net	0.44	0.20	-	0.65	9.51	10.16
Proved plus Probable Undeveloped (2PUD) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	3.94	0.00	1.41	5.35	-	5.35
	net	3.38	0.00	1.22	4.60	-	4.60
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	9.61	9.61
	net	-	-	-	-	8.84	8.84
Conventional Natural Gas (Bscf)	gross	-	0.06	-	0.06	1.12	1.18
	net	-	0.06	-	0.06	1.06	1.12
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.01	0.01
	net	-	-	-	-	0.01	0.01
Total Oil Equivalent (MMboe)	gross	3.94	0.01	1.41	5.36	9.81	15.18
	net	3.38	0.01	1.22	4.61	9.03	13.64
Total Probable (PB) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	8.79	0.02	5.15	13.96	-	13.96
	net	7.75	0.02	4.41	12.17	-	12.17
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	8.44	8.44
	net	-	-	-	-	7.73	7.73
Conventional Natural Gas (Bscf)	gross	-	4.99	-	4.99	81.28	86.27
	net	-	4.99	-	4.99	76.53	81.52
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.07	0.07
	net	-	-	-	-	0.05	0.05
Total Oil Equivalent (MMboe)	gross	8.79	0.85	5.15	14.79	22.06	36.85
	net	7.75	0.85	4.41	13.01	20.53	33.54
Total Proved plus Probable (2P) Reserves							
Light & Medium Crude Oil (MMbbl)	gross	17.61	0.04	9.06	26.70	-	26.70
	net	15.43	0.04	7.77	23.24	-	23.24
Heavy Crude Oil (MMbbl)	gross	-	-	-	-	27.33	27.33
	net	-	-	-	-	25.66	25.66
Conventional Natural Gas (Bscf)	gross	-	10.82	-	10.82	439.13	449.95
	net	-	10.82	-	10.82	415.75	426.57
Natural Gas Liquids (MMbbl)	gross	-	-	-	-	0.10	0.10
	net	-	-	-	-	0.07	0.07
Total Oil Equivalent (MMboe)	gross	17.61	1.84	9.06	28.51	100.62	129.12
	net	15.43	1.84	7.77	25.04	95.02	120.06

Proved plus Probable plus Possible Reserves (Aggregated)

Proved plus Probable plus Possible Developed Producing (3PDP) Reserves

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Light & Medium Crude Oil (MMbbl)	gross	20.56	0.05	9.78	**30.39**	-	**30.39**
	net	18.19	0.05	8.38	**26.62**	-	**26.62**
Heavy Crude Oil (MMbbl)	gross				**-**	21.67	**21.67**
	net				**-**	20.45	**20.45**
Conventional Natural Gas (Bscf)	gross		15.87		**15.87**	427.11	**442.98**
	net		15.87		**15.87**	404.79	**420.67**
Natural Gas Liquids (MMbbl)	gross				**-**	0.04	**0.04**
	net				**-**	0.03	**0.03**
Total Oil Equivalent (MMboe)	gross	20.56	2.70	9.78	**33.04**	92.90	**125.94**
	net	18.19	2.70	8.38	**29.26**	87.95	**117.21**

Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Light & Medium Crude Oil (MMbbl)	gross	0.59	0.00	-	**0.60**	-	**0.60**
	net	0.51	0.00	-	**0.52**	-	**0.52**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**	0.52	**0.52**
	net	-	-	-	**-**	0.42	**0.42**
Conventional Natural Gas (Bscf)	gross	-	1.88	-	**1.88**	69.29	**71.17**
	net	-	1.88	-	**1.88**	65.25	**67.12**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**	0.06	**0.06**
	net	-	-	-	**-**	0.04	**0.04**
Total Oil Equivalent (MMboe)	gross	0.59	0.32	-	**0.91**	12.12	**13.03**
	net	0.51	0.32	-	**0.83**	11.33	**12.16**

Proved plus Probable plus Possible Undeveloped (3PUD) Reserves

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Light & Medium Crude Oil (MMbbl)	gross	4.74	0.00	1.99	**6.73**	-	**6.73**
	net	4.05	0.00	1.67	**5.72**	-	**5.72**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**	12.31	**12.31**
	net	-	-	-	**-**	11.09	**11.09**
Conventional Natural Gas (Bscf)	gross	-	0.12	-	**0.12**	1.42	**1.55**
	net	-	0.12	-	**0.12**	1.34	**1.46**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**	0.02	**0.02**
	net	-	-	-	**-**	0.02	**0.02**
Total Oil Equivalent (MMboe)	gross	4.74	0.02	1.99	**6.75**	12.56	**19.32**
	net	4.05	0.02	1.67	**5.74**	11.33	**17.07**

Total Possible (PS) Reserves

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Light & Medium Crude Oil (MMbbl)	gross	8.29	0.02	2.71	**11.02**	-	**11.02**
	net	7.32	0.02	2.28	**9.62**	-	**9.62**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**	7.17	**7.17**
	net	-	-	-	**-**	6.30	**6.30**
Conventional Natural Gas (Bscf)	gross	-	7.05	-	**7.05**	58.70	**65.75**
	net	-	7.05	-	**7.05**	55.63	**62.68**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**	0.01	**0.01**
	net	-	-	-	**-**	0.01	**0.01**
Total Oil Equivalent (MMboe)	gross	8.29	1.20	2.71	**12.20**	16.96	**29.16**
	net	7.32	1.20	2.28	**10.79**	15.58	**26.38**

Total Proved plus Probable plus Possible (3P) Reserves

		France	Netherlands	Malaysia	Sub Total IPC International	Canada	Total IPC
Light & Medium Crude Oil (MMbbl)	gross	25.89	0.06	11.77	**37.72**	-	**37.72**
	net	22.75	0.06	10.04	**32.85**	-	**32.85**
Heavy Crude Oil (MMbbl)	gross	-	-	-	**-**	34.49	**34.49**
	net	-	-	-	**-**	31.96	**31.96**
Conventional Natural Gas (Bscf)	gross	-	17.87	-	**17.87**	497.82	**515.69**
	net	-	17.87	-	**17.87**	471.38	**489.25**
Natural Gas Liquids (MMbbl)	gross	-	-	-	**-**	0.12	**0.12**
	net	-	-	-	**-**	0.08	**0.08**
Total Oil Equivalent (MMboe)	gross	25.89	3.04	11.77	**40.70**	117.58	**158.28**
	net	22.75	3.04	10.04	**35.83**	110.60	**146.44**

Net Present Value of Future Net Revenue – Proved Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved Developed Producing (PDP) Reserves													
France	93.2	91.7	86.6	82.7	72.8	63.9	60.2	68.5	67.4	65.6	59.7	53.7	14.74
Netherlands	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-23.7	-10.2	-5.3	-2.8	1.3	3.7	-3.21
Malaysia	120.7	114.9	111.7	109.7	105.1	100.9	120.7	114.9	111.7	109.7	105.1	100.9	39.33
Subtotal IPC International	**190.1**	**196.4**	**193.0**	**189.5**	**179.1**	**168.5**	**157.2**	**173.3**	**173.8**	**172.5**	**166.1**	**158.3**	**20.42**
Canada	534.7	519.6	480.9	454.1	393.0	343.2	419.3	427.9	399.9	379.1	330.0	289.1	6.99
Grand Total IPC	**724.8**	**716.0**	**673.9**	**643.7**	**572.1**	**511.7**	**576.5**	**601.2**	**573.7**	**551.6**	**496.0**	**447.4**	**8.67**
Proved Developed Non Producing (PDNP) Reserves													
France	1.7	0.9	0.6	0.4	0.1	-0.1	1.3	0.7	0.4	0.3	0.0	-0.1	2.67
Netherlands	0.7	1.6	1.8	1.9	1.9	1.8	0.7	1.6	1.8	1.9	1.9	1.8	19.22
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**2.4**	**2.5**	**2.4**	**2.3**	**2.0**	**1.7**	**2.0**	**2.3**	**2.2**	**2.2**	**1.9**	**1.6**	**8.84**
Canada	45.8	31.5	25.4	22.1	15.6	11.0	34.3	22.7	17.8	15.2	10.1	6.6	5.02
Grand Total IPC	**48.2**	**34.0**	**27.8**	**24.4**	**17.6**	**12.6**	**36.3**	**24.9**	**20.0**	**17.3**	**12.0**	**8.2**	**5.24**
Proved Undeveloped (PUD) Reserves													
France	66.1	33.8	22.2	16.5	6.7	1.0	48.8	24.6	15.8	11.4	3.8	-0.7	8.61
Netherlands	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	30.09
Malaysia	32.3	30.3	29.2	28.6	27.0	25.6	32.3	30.3	29.2	28.6	27.0	25.6	50.18
Subtotal IPC International	**98.6**	**64.3**	**51.7**	**45.3**	**33.9**	**26.8**	**81.3**	**55.2**	**45.3**	**40.2**	**31.0**	**25.1**	**18.18**
Canada	136.4	69.4	48.6	38.8	22.6	13.0	117.0	55.8	37.4	28.9	15.2	7.2	7.51
Grand Total IPC	**235.1**	**133.8**	**100.3**	**84.1**	**56.5**	**39.8**	**198.3**	**111.0**	**82.7**	**69.1**	**46.2**	**32.4**	**10.98**
Total Proved (1P) Reserves													
France	161.0	126.4	109.4	99.6	79.6	64.8	110.3	93.8	83.6	77.3	63.5	52.8	12.96
Netherlands	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-22.8	-8.3	-3.2	-0.7	3.4	5.7	-0.75
Malaysia	153.0	145.2	140.9	138.3	132.1	126.5	153.0	145.2	140.9	138.3	132.1	126.5	41.16
Subtotal IPC International	**291.2**	**263.3**	**247.1**	**237.1**	**215.1**	**197.0**	**240.5**	**230.7**	**221.3**	**214.8**	**199.0**	**185.0**	**19.70**
Canada	717.0	620.5	554.9	515.0	431.2	367.1	570.6	506.4	455.1	423.2	355.2	302.9	6.91
Grand Total IPC	**1'008.1**	**883.7**	**802.0**	**752.1**	**646.3**	**564.2**	**811.1**	**737.1**	**676.4**	**638.0**	**554.3**	**487.9**	**8.69**

Net Present Value of Future Net Revenue – Proved plus Probable Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD / net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved plus Probable Developed Producing (2PDP) Reserves													
France	333.3	235.6	194.9	173.7	135.4	110.4	230.9	177.8	150.4	135.5	107.7	89.1	14.97
Netherlands	-6.1	8.6	12.6	14.3	16.5	17.0	-7.5	7.3	11.4	12.4	15.3	15.9	8.81
Malaysia	305.9	274.1	258.0	248.3	227.1	209.4	305.9	274.1	258.0	248.3	227.1	209.4	37.90
Subtotal IPC International	**633.1**	**518.3**	**465.5**	**436.4**	**379.0**	**336.9**	**529.4**	**459.1**	**419.7**	**396.2**	**350.1**	**314.5**	**22.06**
Canada	761.3	664.6	593.7	550.9	461.9	395.0	602.3	542.8	487.9	453.9	382.2	327.9	7.20
Grand Total IPC	**1'394.4**	**1'182.9**	**1'059.3**	**987.2**	**840.8**	**731.9**	**1'131.7**	**1'002.0**	**907.7**	**850.1**	**732.3**	**642.4**	**10.26**
Proved plus Probable Developed Non Producing (2PDNP) Reserves													
France	4.0	4.1	3.1	2.5	1.5	0.9	2.4	3.2	2.5	2.0	1.1	0.6	5.74
Netherlands	3.3	4.2	4.2	4.0	3.5	3.0	2.5	3.5	3.5	3.4	2.9	2.5	19.62
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	**7.2**	**8.3**	**7.3**	**6.6**	**5.0**	**3.9**	**4.9**	**6.8**	**6.0**	**5.4**	**4.0**	**3.1**	**10.13**
Canada	115.1	78.7	63.5	55.3	39.6	28.7	84.9	56.6	44.9	38.7	26.8	18.8	5.81
Grand Total IPC	**122.4**	**87.1**	**70.8**	**61.8**	**44.6**	**32.6**	**89.8**	**63.4**	**50.9**	**44.1**	**30.9**	**21.8**	**6.09**
Proved plus Probable Undeveloped (2PUD) Reserves													
France	137.4	82.6	62.1	51.7	33.2	21.3	101.0	60.2	44.6	36.7	22.5	13.3	15.29
Netherlands	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.8	0.1	0.1	19.70
Malaysia	85.5	76.9	72.6	70.0	64.3	59.5	85.5	76.9	72.6	70.0	64.3	59.5	57.58
Subtotal IPC International	223.2	159.7	134.9	121.9	97.7	81.0	186.6	137.3	117.3	107.4	86.8	72.9	26.45
Canada	295.7	143.4	101.2	82.1	51.1	33.1	245.2	110.7	75.3	59.6	34.8	20.8	9.09
Grand Total IPC	518.9	303.1	236.1	204.0	148.8	114.1	431.9	248.0	192.6	167.0	121.6	93.7	14.95
Total Probable (PB) Reserves													
France	313.7	195.9	150.8	128.5	90.5	67.8	224.0	147.3	113.8	96.9	67.7	50.3	16.58
Netherlands	20.2	21.4	20.2	19.3	16.8	14.5	18.0	19.3	18.2	17.3	14.9	12.8	22.72
Malaysia	238.5	205.8	189.7	180.0	159.3	142.4	238.5	205.8	189.7	180.0	159.3	142.4	40.84
Subtotal IPC International	**572.4**	**423.1**	**360.7**	**327.8**	**266.6**	**224.7**	**480.4**	**372.4**	**321.7**	**294.2**	**241.9**	**205.4**	**25.20**
Canada	455.1	266.2	203.5	173.2	121.4	89.8	361.9	203.8	153.1	129.0	88.6	64.6	8.43
Grand Total IPC	**1'027.5**	**689.3**	**564.2**	**500.9**	**387.9**	**314.4**	**842.3**	**576.2**	**474.8**	**423.2**	**330.6**	**270.0**	**14.94**
Total Proved plus Probable (2P) Reserves													
France	474.7	322.3	260.1	228.0	170.1	132.6	334.3	241.2	197.4	174.1	131.3	103.1	14.78
Netherlands	-2.6	13.0	17.0	18.5	20.2	20.2	-4.8	11.0	15.0	16.6	18.3	18.5	10.08
Malaysia	391.4	351.0	330.6	318.3	291.4	268.9	391.4	351.0	330.6	318.3	291.4	268.9	40.98
Subtotal IPC International	**863.5**	**686.4**	**607.8**	**564.9**	**481.6**	**421.7**	**720.9**	**603.1**	**543.0**	**509.0**	**441.0**	**390.5**	**22.56**
Canada	1'172.1	886.7	758.4	688.2	552.5	456.9	932.4	710.2	608.2	552.2	443.9	367.4	7.24
Grand Total IPC	**2'035.6**	**1'573.1**	**1'366.2**	**1'253.1**	**1'034.2**	**878.6**	**1'653.4**	**1'313.3**	**1'151.2**	**1'061.2**	**884.8**	**757.9**	**10.44**

Net Present Value of Future Net Revenue – Proved plus Probable plus Possible Reserves (Aggregated)

	Before Deducting Income Tax, Discounted at:						After Deducting Income Tax, Discounted at:						USD/ net BOE
Values in MUSD	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**	**BTAX NPV10**
Proved plus Probable plus Possible Developed Producing (3PDP) Reserves													
France	818.8	432.2	323.8	275.5	199.5	156.4	584.6	324.1	246.3	211.1	155.1	123.1	15.15
Netherlands	32.0	35.0	34.7	34.0	31.8	29.3	22.3	27.4	27.9	27.8	26.2	24.4	12.61
Malaysia	440.3	386.1	359.4	343.5	309.4	281.6	440.3	386.1	359.4	343.5	309.4	281.6	41.01
Subtotal IPC International	1'291.1	853.3	717.9	653.1	540.7	467.3	1'047.3	737.6	633.6	582.5	490.8	429.1	22.32
Canada	1'013.9	791.6	658.4	626.6	512.6	431.6	811.9	642.8	558.5	511.6	420.1	354.9	7.13
Grand Total IPC	2'305.0	1'644.9	1'376.2	1'279.7	1'053.3	899.0	1'859.1	1'380.4	1'192.1	1'094.1	910.9	784.0	10.92
Proved plus Probable plus Possible Developed Non Producing (3PDNP) Reserves													
France	16.7	7.1	4.8	3.9	2.4	1.6	12.4	5.3	3.5	2.8	1.7	1.1	7.51
Netherlands	8.1	7.3	6.4	5.9	4.6	3.7	6.8	6.1	5.3	4.8	3.7	2.9	18.55
Malaysia	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal IPC International	24.8	14.5	11.3	9.7	7.0	5.3	19.1	11.3	8.8	7.6	5.4	4.0	11.72
Canada	156.2	107.7	87.1	75.9	54.7	40.0	114.1	77.5	62.0	53.7	37.8	27.0	6.70
Grand Total IPC	181.0	122.1	98.4	85.7	61.7	45.3	133.2	88.8	70.9	61.3	43.2	31.0	7.05
Proved plus Probable plus Possible Undeveloped (3PUD) Reserves													
France	191.7	115.2	87.3	73.3	48.8	33.4	140.7	83.4	62.3	51.7	33.1	21.4	18.09
Netherlands	0.7	0.7	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.4	0.4	30.40
Malaysia	117.8	104.9	98.4	94.6	86.2	79.3	96.6	87.3	82.6	79.8	73.7	68.5	56.79
Subtotal IPC International	310.1	220.8	186.4	168.6	135.6	113.3	237.7	171.1	145.4	131.8	107.1	90.3	29.37
Canada	435.9	205.0	144.8	117.9	74.9	50.2	344.0	154.3	106.2	85.1	51.9	33.1	10.40
Grand Total IPC	746.0	425.8	331.2	286.4	210.5	163.5	581.7	325.5	251.6	216.9	159.0	123.4	16.78
Total Possible (PS) Reserves													
France	552.5	232.2	155.8	124.7	80.6	58.8	403.4	171.5	114.7	91.5	58.6	42.5	17.03
Netherlands	43.4	30.0	24.8	22.0	16.9	13.4	34.4	23.0	18.6	16.3	12.0	9.2	18.37
Malaysia	166.6	140.0	127.2	119.8	104.2	92.0	145.4	122.4	111.5	105.1	91.7	81.2	52.67
Subtotal IPC International	762.5	402.2	307.8	266.5	201.7	164.2	583.2	316.9	244.8	212.9	162.3	132.9	24.69
Canada	433.8	217.6	158.8	132.2	89.6	65.0	337.5	164.5	118.6	98.2	65.9	47.6	8.49
Grand Total IPC	1'196.3	619.8	466.5	398.8	291.3	229.2	920.7	481.4	363.3	311.1	228.3	180.5	15.12
Total Proved plus Probable plus Possible (3P) Reserves													
France	1'027.1	554.5	415.9	352.7	250.7	191.4	737.7	412.7	312.2	265.7	189.9	145.6	15.50
Netherlands	40.8	43.0	41.8	40.6	37.0	33.6	29.6	33.9	33.6	32.9	30.3	27.6	13.35
Malaysia	558.0	491.0	457.8	438.1	395.6	360.9	536.8	473.4	442.1	423.4	383.1	350.1	43.63
Subtotal IPC International	1'626.0	1'088.5	915.5	831.4	683.4	585.9	1'304.1	920.1	787.8	721.9	603.3	523.3	23.20
Canada	1'605.9	1'104.3	917.2	820.4	642.2	521.9	1'270.0	874.6	726.7	650.4	509.8	415.0	7.42
Grand Total IPC	3'232.0	2'192.8	1'832.7	1'651.8	1'325.5	1'107.8	2'574.1	1'794.7	1'514.5	1'372.2	1'113.1	938.4	11.28

Elements of Future Net Revenue (Aggregated)

Total Proved (1P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	693.8	86.1	335.3	32.4	78.9	161.0	50.7	110.3
Netherlands	48.5	-	27.9	0.9	42.4	- 22.8	-	- 22.8
Malaysia	449.5	26.9	236.2	8.9	24.5	153.0	-	153.0
Subtotal IPC International	**1'191.8**	**113.1**	**599.5**	**42.2**	**145.8**	**291.2**	**50.7**	**240.5**
Canada	2'015.9	92.9	735.5	138.5	332.1	717.0	146.4	570.6
Grand Total IPC	**3'207.7**	**206.0**	**1'335.0**	**180.8**	**477.9**	**1'008.1**	**197.1**	**811.1**

Total Proved and Probable (2P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	1'560.1	181.6	743.1	51.4	109.4	474.7	140.4	334.3
Netherlands	88.9	-	44.7	0.9	45.8	- 2.6	2.2	- 4.8
Malaysia	875.8	66.2	381.3	8.9	27.9	391.4	-	391.4
Subtotal IPC International	**2'524.8**	**247.8**	**1'169.1**	**61.2**	**183.1**	**863.5**	**142.6**	**720.9**
Canada	2'814.6	152.1	955.9	184.3	350.2	1'172.1	239.7	932.4
Grand Total IPC	**5'339.4**	**399.9**	**2'125.0**	**245.5**	**533.3**	**2'035.6**	**382.2**	**1'653.4**

Total Proved and Probable and Possible (3P) Reserves MUSD	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
France	2'428.8	275.2	943.0	57.1	126.4	1'027.1	289.4	737.7
Netherlands	147.4	-	65.4	0.9	40.2	40.8	11.3	29.6
Malaysia	1'084.2	86.5	402.8	8.9	27.9	558.0	21.2	536.8
Subtotal IPC International	**3'660.4**	**361.7**	**1'411.3**	**66.9**	**194.5**	**1'626.0**	**321.9**	**1'304.1**
Canada	3'502.8	219.0	1'137.9	184.3	355.8	1'605.9	335.9	1'270.0
Grand Total IPC	**7'163.2**	**580.7**	**2'549.1**	**251.2**	**550.2**	**3'232.0**	**657.9**	**2'574.1**

Net Present Value by Product Type (Aggregated)

IPC Total Future Net Revenue BTAX at 10% Discount	Primary Product Type Light & Medium Crude Oil (MUSD)	Heavy Crude Oil (MUSD)	Conventional Natural Gas (MUSD)	Natural Gas Liquids (MUSD)	Total (MUSD)
Total Proved (1P) Reserves	237.8	236.6	277.7	-	752.1
Total Proved and Probable (2P) Reserves	546.3	340.6	366.2	-	1'253.1
Total Proved and Probable and Possible (3P) Reserves	790.8	429.3	431.7	-	1'651.8

IPC Total USD per boe by product type	Primary Product Type Light & Medium Crude Oil (USD/bbl)	Heavy Crude Oil (USD/bbl)	Conventional Natural Gas (USD/Mscf)	Natural Gas Liquids (USD/bbl)	Total (USD/boe)
Total Proved (1P) Reserves	21.5	13.20	0.81	-	8.76
Total Proved and Probable (2P) Reserves	23.5	13.27	0.86	-	10.47
Total Proved and Probable and Possible (3P) Reserves	24.1	13.43	0.89	-	11.36

Notes
(1) Light, Medium, and Heavy Oil Future Net Revenue and Unit Value include associated gas
(2) Conventional natural Gas revenue and unit Value include associated condensate (light oil)

Forecast Prices used in Estimates (Aggregated)

See “IPC’s Oil and Gas Assets in France, Malaysia and the Netherlands - Forecast Prices used in Estimates” and “IPC’s Oil and Gas Assets in Canada - Forecast Prices used in Estimates” above.

Reconciliation of Changes in Reserves (Aggregated)

Reconciliation of Proved Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International** **Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada** **Oil Equivalent**	**IPC Total** **Oil Equivalent**
Opening Balance December 31, 2016	4.9	11.3	0.9	**17.0**	-	-	-	**-**	**17.0**
extensions and improved recovery	+ 0.7	+ 0.0	+ 0.0	**+ 0.7**				**+ 0.0**	**+ 0.7**
technical revisions	+ 0.8	- 0.5	+ 0.5	**+ 0.8**				**+ 0.0**	**+ 0.8**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 18.9	+ 59.6	+ 0.0	**+ 78.6**	**+ 78.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	+ 0.0	- 1.1	+ 0.0	**- 1.1**				**+ 0.0**	**- 1.1**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	3.9	8.8	1.0	**13.7**	18.9	59.6	0.0	**78.6**	**92.3**

Reconciliation of Proved + Probable Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International** **Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada** **Oil Equivalent**	**IPC Total** **Oil Equivalent**
Opening Balance December 31, 2016	9.5	18.0	1.8	**29.4**	-	-	-	**-**	**29.4**
extensions and improved recovery	+ 1.4	+ 0.5	+ 0.0	**+ 1.9**				**+ 0.0**	**+ 1.9**
technical revisions	+ 0.8	+ 0.3	+ 0.4	**+ 1.6**				**+ 0.0**	**+ 1.6**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 27.3	+ 73.2	+ 0.1	**+ 100.6**	**+ 100.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	- 0.3	- 0.3	+ 0.0	**- 0.6**				**+ 0.0**	**- 0.6**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	9.1	17.6	1.8	**28.5**	27.3	73.2	0.1	**100.6**	**129.1**

Reconciliation of Proved + Probable + Possible Reserves Mmboe	Malaysia Light & Medium Oil	France Light & Medium Oil	Netherlands Convent-ional Natural Gas	**Sub-Total International** **Oil Equivalent**	Canada Heavy Oil	Canada Convent-ional Natural Gas	Canada Natural Gas Liquids	**Sub-Total Canada** **Oil Equivalent**	**IPC Total** **Oil Equivalent**
Opening Balance December 31, 2016	13.3	23.8	3.2	**40.3**	-	-	-	**-**	**40.3**
extensions and improved recovery	+ 2.0	+ 0.7	+ 0.0	**+ 2.7**				**+ 0.0**	**+ 2.7**
technical revisions	- 1.1	+ 2.3	+ 0.3	**+ 1.5**				**+ 0.0**	**+ 1.5**
discoveries				**+ 0.0**				**+ 0.0**	**+ 0.0**
acquisitions				**+ 0.0**	+ 34.5	+ 83.0	+ 0.1	**+ 117.6**	**+ 117.6**
dispositions				**+ 0.0**				**+ 0.0**	**+ 0.0**
economic factors	+ 0.0	- 0.0	+ 0.0	**- 0.0**				**+ 0.0**	**- 0.0**
production	- 2.4	- 0.9	- 0.4	**- 3.7**				**+ 0.0**	**- 3.7**
Closing Balance December 31, 2017	11.8	25.9	3.0	**40.7**	34.5	83.0	0.1	**117.6**	**158.3**

Undeveloped Reserves (Aggregated)

	Light & Medium Crude Oil (MMbbl)	Heavy Crude Oil (MMbbl)	Conventional Natural Gas (Bscf)	Natural Gas Liquids (MMboe)	Oil Equivalent (MMboe)
Proved Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.1	-	-	-	3.1
December 31, 2017	0.7	5.4	0.6	0.0	6.2
Probable Undeveloped					
December 31, 2015	-	-	-	-	-
December 31, 2016	3.3	-	-	-	3.3
December 31, 2017	1.4	9.6	1.1	0.0	11.2

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Undeveloped Reserves" and "IPC's Oil and Gas Assets in Canada – Undeveloped Reserves" above.

IPC Development Projects (Aggregated)

	Light & Medium Crude Oil Reserves MMbbl gross	Heavy Crude Oil Reserves MMbbl gross	Conventional Natural Gas Reserves Bscf Gross	Future Project Development Capital MUSD			USD per boe	Net Present Value, MUSD Before Deducting Income Tax, Discounted at:						Net Present Value, MUSD After Deducting Income Tax, Discounted at:						BTAX NPV10 per boe USD per boe	ATAX NPV10 per boe USD per boe
				2018	2019	Total		0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%		
France - Vert La Gravelle Redevelopment																					
Proved Undeveloped (PUD)	2.2	-	-	0.9	24.8	25.8	11.5	66	34	22	16	7	1	49	25	16	11	4	-1	7.37	5.10
Proved and Probable Undeveloped (PPUD)	3.9	-	-	0.9	39.1	44.3	11.2	137	83	62	52	33	21	101	60	45	37	22	13	13.13	9.30
Proved plus Probable plus Possible Undeveloped (PPPUD)	4.7	-	-	0.9	39.1	49.8	10.5	192	115	87	73	49	33	141	83	62	52	33	21	15.47	10.90
Malaysia - A16 and A17 Development Wells																					
Proved Undeveloped (PUD)	0.7	-	-	7.7	-	7.7	11.7	32	30	29	29	27	26	32	30	29	29	27	26	43.15	43.15
Proved and Probable Undeveloped (PPUD)	1.4	-	-	7.7	-	7.7	5.5	85	77	73	70	64	59	85	77	73	70	64	59	49.52	49.52
Proved plus Probable plus Possible Undeveloped (PPPUD)	2.0	-	-	7.7	-	7.7	3.9	118	105	98	95	86	79	97	87	83	80	74	68	47.50	40.10
Canada - Oil Drilling and EOR																					
Proved Undeveloped (PUD)	-	5.4	0.6	4.1	16.4	43.1	7.8	142	70	49	39	23	13	117	56	37	29	15	7	7.03	5.21
Proved and Probable Undeveloped (PPUD)	-	9.6	1.1	4.1	22.8	65.6	6.7	296	143	101	82	51	33	245	111	75	60	35	21	8.37	6.08
Proved plus Probable plus Possible Undeveloped (PPPUD)	-	12.3	1.4	4.1	22.8	65.6	5.2	436	205	145	118	75	50	344	154	106	85	22	33	9.39	6.78
Total IPC																					
Proved Undeveloped (PUD)	**2.9**	**5.4**	**0.6**	**12.7**	**41.2**	**76.6**	**31.0**	**241**	**134**	**100**	**84**	**56**	**40**	**198**	**111**	**82**	**69**	**46**	**32**	**9.95**	**8.15**
Proved and Probable Undeveloped (PPUD)	**5.4**	**9.6**	**1.1**	**12.7**	**61.9**	**117.6**	**23.4**	**519**	**303**	**236**	**204**	**149**	**114**	**432**	**248**	**193**	**166**	**122**	**94**	**13.45**	**10.97**
Proved plus Probable plus Possible Undeveloped (PPPUD)	**6.7**	**12.3**	**1.4**	**12.7**	**61.9**	**123.1**	**19.6**	**745**	**425**	**331**	**286**	**210**	**163**	**581**	**325**	**251**	**217**	**129**	**123**	**14.82**	**11.24**

Significant Factors or Uncertainties Affecting Reserves Data (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Significant Factors or Uncertainties Affecting Reserves Data" and "IPC's Oil and Gas Assets in Canada – Significant Factors or Uncertainties Affecting Reserves Data" above.

Future Development Costs (Aggregated)

	2018	2019	2020	2021	2022	2023 on	Total for all years undiscounted	**Total for all years discounted at 10% p.a.**
Total Proved								
Canada	6.8	29.7	33.1	16.5	3.2	49.3	138.5	**86.4**
France	5.1	26.2	1.1	-	-	-	32.4	**28.4**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	21.8	55.8	34.2	16.5	3.2	49.3	180.8	**124.4**
Total Proved Plus Probable								
Canada	6.8	36.0	39.0	18.2	14.8	69.3	184.3	**116.7**
France	5.3	40.7	5.4	-	-	-	51.4	**44.5**
Netherlands	0.9	-	-	-	-	-	0.9	**0.9**
Malaysia	8.9	-	-	-	-	-	8.9	**8.8**
Total	22.0	76.7	44.4	18.2	14.8	69.3	245.5	**170.8**

Expectations of Sources and Costs of Funding (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Expectations of Sources and Costs of Funding" and "IPC's Oil and Gas Assets in Canada – Expectations of Sources and Costs of Funding" above.

Producing and Non-Producing Well Counts (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Producing and Non-Producing Well Counts" and "IPC's Oil and Gas Assets in Canada – Producing and Non-Producing Well Counts" above.

Properties with No Attributed Reserves (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Properties with No Attributed Reserves" and "IPC's Oil and Gas Assets in Canada – Properties with No Attributed Reserves" above.

Tax Horizon (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Tax Horizon" and "IPC's Oil and Gas Assets in Canada – Tax Horizon" above.

Production Forecast Estimates (Aggregated)

	Light & Medium Crude Oil (Mbbl/d)	Heavy Crude Oil (Mbbl/d)	Conventional Natural Gas (Mboe/d)	Natural Gas Liquids (Mboe/d)	Total (Mboe/d)
Total Proved (1P) Scenario					
France	1.96	-	-	-	1.96
Netherlands	0.02	-	0.79	-	0.80
Malaysia	5.29	-	-	-	5.29
Subtotal IPC International	**7.27**	**-**	**0.79**	**-**	**8.05**
Canada	-	6.12	16.10	-	22.22
Total IPC	**7.27**	**6.12**	**16.88**	**-**	**30.27**
Total Proved plus Probable (2P) Scenario					
France	2.31	-	-	-	2.31
Netherlands	0.02	-	0.94	-	0.96
Malaysia	6.58	-	-	-	6.58
Subtotal IPC International	**8.92**	**-**	**0.94**	**-**	**9.86**
Canada	-	6.32	16.27	-	22.59
Total IPC	**8.92**	**6.32**	**17.21**	**-**	**32.45**
Total Proved plus Probable plus Possible (3P) Scenario					
France	2.62	-	-	-	2.62
Netherlands	0.02	-	1.08	-	1.10
Malaysia	7.72	-	-	-	7.72
Subtotal IPC International	**10.36**	**-**	**1.08**	**-**	**11.44**
Canada	-	6.41	16.38	-	22.79
Total IPC	**10.36**	**6.41**	**17.46**	**-**	**34.23**

Contingent Resources (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Contingent Resources" and "IPC's Oil and Gas Assets in Canada – Contingent Resources" above.

Prospective Resources (Aggregated)

See "IPC's Oil and Gas Assets in France, Malaysia and the Netherlands – Prospective Resources" above.

DIVIDENDS AND DISTRIBUTIONS

The Corporation does not currently anticipate paying any dividends on its Common Shares. The Corporation currently intends to utilize its earnings to finance the growth and development of its business and to otherwise reinvest in its business. Any decision to pay dividends on the Common Shares in the future will be made by the Board on the basis of the Corporation's earnings and financial requirements as well as other conditions existing at such time. Unless the Corporation commences the payment of dividends, holders of Common Shares will not be able to receive a return on their Common Shares unless they sell them.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without par value, of which 87,921,846 are issued and outstanding as at December 31, 2017 and as at the date of this AIF.

All of the Common Shares outstanding are fully paid and non-assessable. Holders of Common Shares are entitled to dividends, if, as and when declared by the Board, to receive notice of meetings of shareholders of the Corporation, to one vote per share at meetings of the shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares. Holders of Common Shares do not have cumulative voting rights with respect to the election of directors and, accordingly, holders of a majority of the votes eligible to vote at a meeting of shareholders may elect all the directors of the Corporation standing for election. Dividends, if any, will be paid on a pro rata basis only from funds legally available therefor.

Preferred shares

The Corporation is authorized to issue an unlimited number of Class A Preferred Shares (the "Class A Preferred Shares"), of which 117,485,389 are issued and outstanding at December 31, 2017 and at the date of the AIF, and an unlimited number of Class B Preferred Shares (the "Class B Preferred Shares"), issuable in series, none of which is issued and outstanding. All of the issued and outstanding Class A Preferred Shares of the Corporation are held by a subsidiary of the Corporation.

The Class A Preferred Shares are not listed on any stock exchange and do not carry the right to vote on matters to be decided by the holders of IPC's common shares. The Class A Preferred Shares are entitled to non-cumulative dividends at a rate of 5% per year (in priority to dividends on all other classes of shares of the Corporation), if, as and when declared by the Board; and no dividends may be declared or paid to holders of any other class of shares of the Corporation without the consent of the majority of the holders of the Class A Preferred Shares, acting together as a class, if the declaration and payment of such dividend would impede the ability of the Corporation to satisfy the aggregate Redemption Amount in respect of the Class A Preferred Shares.

The Class B Preferred Shares, if issued, will have priority over the Common Shares with respect to dividends and other distributions, including the distribution of assets upon liquidation, dissolution or winding-up of the Corporation. Unless required by law or by applicable stock exchanges, the Board has the authority without further shareholder authorization to issue from time to time the Class B Preferred Shares in one or more series, to fix the terms, special rights and restrictions of each series and to make any necessary alterations to its articles to effect the change.

Share-based plans

The Group has the following share-based compensation plans for its employees, consultants and directors: a stock option plan ("Stock Option Plan") and a one- time transitional performance and restricted share plan, under which awards have been made in performance shares ("IPC transitional PSP) or in restricted shares ("IPC transitional RSP") in connection with the Spin-Off.

The Stock Option Plan gives the participants a right to buy common shares of IPC at an exercise price equal to the market value at the date of grant. The Board granted stock options under the Stock Option Plan on February 21, 2017 with a three year vesting period and a four year term, whereby the stock options vest equally in three tranches: one third after one year, one third after two years and the final third after three years. The plan is effective from February 21, 2017 and the total outstanding number of stock options at December 31, 2017 is 1,856,600, with an exercise price of CAD 4.77.

In connection with the Spin-Off, the Group agreed to put in place certain one-time transitional equity-based compensation plans for certain officers and employees of the Group. The IPC transitional PSP and IPC transitional RSP awards were made effective as of April 24, 2017 and vest subject to certain conditions.

Under the IPC Transitional PSP Plan, 75 percent of the awards will vest subject to continued employment only and the remaining 25 percent will vest subject to continued employment and on a straight-line basis for the share price performance between 100 percent and 125 percent of CAD 4.77. The number of awards outstanding under the IPC Transitional PSP Plan at December 31, 2017 amounts to 1,154,569.

Under the IPC Transitional RSP Plan, the awards will vest subject to continued employment only. The number of awards outstanding under the IPC Transitional RSP Plan at December 31, 2017 amounts to 152,790.

MARKET FOR SECURITIES

Trading price and volume

The Common Shares are listed for trading on the TSX in Canada and the NASDAQ First North in Sweden under the trading symbol "IPCO", since April 24, 2017.

The following table sets out, for the calendar periods indicated, the high and low closing prices and aggregate trading volumes for the Common Shares as reported on the TSX.

Month	High (CA$)	Low (CA$)	Volume
April 2017	6.31	5.17	532,866
May 2017	5.50	4.21	396,669
June 2017	5.25	3.75	328,544
July 2017	4.35	3.42	89,497
August 2017	6.31	4.06	721,811
September 2017	5.50	4.00	321,269
October 2017	6.36	5.30	95,859
November 2017	6.10	5.21	67,075
December 2017	5.75	5.05	24,478

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2017 and as at the date of this AIF, the Corporation does not have any securities in escrow or that are subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Name and Province and Country of Residence	Position with the Corporation[5]	Number of Common Shares Beneficially Owned or Controlled	Principal Occupation (for last 5 years)
Lukas H. Lundin[1] *Switzerland*	Chair	262,777	Businessman
Mike Nicholson *Switzerland*	CEO, Director	40,000	CFO, Lundin Petroleum until April 2017; Managing Director, IPC Malaysia BV until December 2013
C. Ashley Heppenstall[2][3][4] *Hong Kong*	Lead Director	463,761	President & CEO, Lundin Petroleum until 2015; Businessman
Donald Charter[1][2][4] *Ontario, Canada*	Director	72,333	President & CEO, Corsa Coal Corp. until 2013; Businessman
Chris Bruijnzeels[2][3][4] *Switzerland*	Director	Nil	President & CEO, ShaMaran Petroleum Corp. since 2015; prior thereto, Senior Vice President Development of Lundin Petroleum
Torstein Sanness[1][3] *Norway*	Director	25,037	Managing Director of Lundin Norway until 2014; Businessman
Christophe Nerguararian *Switzerland*	CFO	36,183	Vice-President Corporate Finance, Lundin Petroleum until April 2017; Head of Corporate Debt and Commercial Manager, Lundin Petroleum, until December 2015
Jeffrey Fountain *Switzerland*	General Counsel	26,666	Vice-President Legal, Lundin Petroleum until April 2017
Daniel Fitzgerald *Switzerland*	Vice-President Operations	15,000	Group Operations Manager, Lundin Petroleum until April 2017; Operations Manager, Shell UK Ltd. until September 2014
Ryan Adair *Switzerland*	Vice-President Reservoir Development	Nil	Group Subsurface Manager, Lundin Petroleum until April 2017; Manager Reservoir Engineering, Petrominerales Ltd. until August 2013
Rebecca Gordon *Switzerland*	Vice-President Corporate Planning and Investor Relations	2,100	Group Manager Economics and Planning, Lundin Petroleum until April 2017

Notes:

(1) Member of Compensation Committee.
(2) Member of Audit Committee.
(3) Member of Reserves and HSE Committee.
(4) Member of Nominating and Corporate Governance Committee.
(5) Each of the Directors was appointed in February 2017 for a term until the next Annual General Meeting of Shareholders, to be held in July 2018.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Corporation) that, (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Except as set forth in the following paragraph, no current or proposed director or officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this document, been a director or executive officer of any company (including the Corporation) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt or liquidated, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Lundin was a director of Sirocco Mining Inc. until January 31, 2014, at which time he resigned in connection with its amalgamation with Canada Lithium Corp. Sirocco Mining Inc. was financially solvent at the time of Mr. Lundin's resignation. In October 2014, the resulting entity, RB Energy Inc., filed for protection under the *Companies' Creditors Arrangement Act.* Mr. Lundin has never been a director, officer or control person of RB Energy Inc., however, RB Energy Inc. filed for protection under the Companies' Creditors Arrangement Act within 12 months of Mr. Lundin ceasing to be a director of Sirocco Mining Inc. The amalgamation of Sirocco Mining with Canada Lithium Corp. to form RB Energy Inc. was approved at a meeting of the board of directors of Sirocco Mining Inc. on December 3, 2013. Mr. Lundin voted against the transaction, pursuant to which Sirocco Mining Inc. and Canada Lithium Corp. would complete a business combination by way of a statutory plan of arrangement under the *Canada Business Corporations Act*. The plan of arrangement was approved by shareholders and completed on January 31, 2014. The final step in the transaction was the amalgamation of Canada Lithium Corp. and Sirocco Mining Inc. to form RB Energy Inc. On October 13, 2014, RB Energy Inc.'s board of directors approved an application for the filing of an initial order for creditor protection under the *Companies' Creditors Arrangement Act*. The Quebec Superior Court issued the requested order in respect of RB Energy Inc. and its subsidiaries on October 14, 2014.

No current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years prior to the date of this document, 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, officer or securityholder.

No current or proposed director or executive officer or securityholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court,regulatory body or other authority that would likely be considered important to a reasonable investor in making an investment decision.

No director of the Corporation or any of the executive officers has been disqualified by a court from acting as a member of the administrative, management or supervisory body of a company or from acting as the management or conducting of the affairs of a company during the past five years, or has been evicted of any fraudulent acts.

Conflicts of Interest

Circumstances may arise where members of the Board or officers of the Corporation are directors or officers of companies, which are in competition to the interests of the Corporation. Pursuant to applicable law, directors who have an interest in a proposed transaction upon which the Board is voting are required to disclose their interests and refrain from voting on the transaction.

There is no family relationship between any of the individuals who will be members of the Board or executive officers of the Corporation.

As at December 31, 2017 and as at the date of this AIF, the Group was not aware of any existing or potential material conflicts of interest between the Group and a subsidiary of the Group and a director or officer of the Group or of a subsidiary of the Group.

AUDIT COMMITTEE

Audit Committee Mandate

The Audit Committee Mandate of the Corporation is attached hereto as Schedule "D".

Composition of the Audit Committee

The Audit Committee is comprised of C. Ashley Heppenstall (Chair), Donald Charter and Chris Bruijnzeels, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral Instrument 52-110 – Audit Committees.

Mr. Heppenstall has extensive experience in finance and in the mining, oil and gas and renewable energy industries. He has a degree in Mathematics from Durham University. He worked as a commercial bank executive, following which he served as Chief Financial Officer then Chief Executive Officer of Lundin Petroleum from 1997 to 2015. He is a director on the boards of several public companies.

Mr. Charter has experience as a corporate director and officer of public companies, including in the financial services, natural resource and real estate industries. He has degrees in Economics and Law from McGill University. In addition to his senior executive leadership experience, he has extensive board level experience, including audit, compensation and governance committee chair and member status. He is a member of the Institute of Corporate Directors.

Mr. Bruijnzeels is currently the Chief Executive Officer of ShaMaran Petroleum Corp., with overall responsibility for the managerial, operational and financial functions. He has a degree in Mining Engineering from Delft University. He previously was a member of the Investment Committee of Lundin Petroleum which reported to the board of directors of Lundin Petroleum on investment and financial matters.

Pre-Approval of Policies and Procedures

In accordance with the Audit Committee Mandate, the Audit Committee shall approve in advance any retainer of the external auditor to provide any non-audit service to the Corporation (together with all non-audit service fees) that it deems advisable in accordance with applicable requirements and Board-approved policies and procedures. The Audit Committee shall consider the impact of such service and fees on the independence of the external auditor.

Audit Committee Oversight

Since the commencement of the Corporation's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor that was not adopted by the Board of Directors.

External Auditor Services Fees

The following table discloses the fees billed to the Corporation by PricewaterhouseCoopers AG, Licensed Public Accountants, in the year ended December 31, 2017.

USD Thousands

Financial Year Ending	Audit Fees (1)	Audit Related Fees (2)	Tax Fees (3)	All Other Fees (4)
2017	531	53	17	–

Notes:
(1) The aggregate fees billed for audit services.
(2) The aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the audit fees column.
(3) The aggregate fees billed for tax compliance, tax advice, and tax planning services.
(4) The aggregate fees billed for professional services other than those listed in the other three columns.

PROMOTERS

Lundin Petroleum may be considered a promoter of the Corporation as a result of its management team having been instrumental in founding the business and facilitating the Spin-Off of the Corporation in 2017.

In connection with the reorganization and Spin-Off, all of the shares of International Petroleum BV (then known as Lundin Petroleum BV) and all of the shares of Lundin Services Ltd. were transferred to the Corporation in exchange for the issuance by the Corporation to Lundin Petroleum of an aggregate of 113,462,147 Common Shares based on a price of CAD 4.77 per Common Share, for aggregate consideration of USD 410 million plus working capital as at the effective date. Immediately following the Spin-Off, Lundin Petroleum distributed the 113,462,147 Common Shares to Lundin Petroleum's shareholders. As at the date of this AIF, Lundin Petroleum holds no Common Shares or other securities of the Corporation or any of its subsidiaries.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal proceedings

There are no material legal proceedings against the Corporation or any of its subsidiaries, the Corporation is not a party to any material legal proceedings and the Corporation is not aware of any contemplated proceedings. The Corporation has not in the past twelve months been involved in any governmental, legal or arbitrational proceedings which have had, or may have, significant effect on the Corporation's financial position or profitability. The Corporation is not aware of any such pending or threatened proceedings. See also "**Description of the Business – Discontinued Operations**".

Regulatory actions

For the period beginning on the date of incorporation of the Corporation until the date of this AIF, there were (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Management is not aware of any material interest, direct or indirect, of any director or officer of the Corporation, any person beneficially owning, directly or indirectly, more than 10% of the Corporation's voting securities, or any associate or affiliate of such person in any transaction within the last three years or in any proposed transaction which in either case has materially affected or will materially affect the Corporation or its subsidiaries, other than as disclosed in this AIF.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares in Canada is Computershare Investor Services Inc., and the Common Shares will be transferable at the offices of Computershare (Canada) in Toronto and Calgary. The transfer agent and registrar for the Common Shares in Sweden is Computershare AB, and the Common Shares will be transferable at the offices of Computershare (Sweden) in Stockholm.

MATERIAL CONTRACTS

The following are the only material contracts, other than those contracts entered into in the ordinary course of business, which the Corporation has entered into since the beginning of the last financial year before the date of this AIF, entered into prior to such date but which contract is still in effect:

(a) Transfer Agreement between Lundin Petroleum AB and the Corporation, dated April 7, 2017;
(b) Transfer Agreement between Lundin Petroleum AB and the Corporation, dated April 7, 2017; and
(c) Asset Sale Agreement between Cenovus Energy Inc. and IPC Alberta Ltd., dated September 22, 2017.

For more information in respect of these contracts, see "**General Development of the Business**" above. Copies of these material contracts may be viewed under the Corporation's profile on the SEDAR website at www.sedar.com.

NAMES AND INTERESTS OF EXPERTS

This AIF contains references to estimates of reserves, contingent resources, prospective resources and estimates of future net revenue attributed to the Corporation's oil and gas assets.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel's January 1, 2018 price forecasts as referred to below.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of these assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts

Neither ERCE nor McDaniel, nor any directors, officers, employees or consultants of such firms, beneficially owns, directly or indirectly, any of the outstanding Common Shares, nor have any economic or beneficial interest in the Corporation or in any of its assets, nor are they remunerated by way of a fee that is lined to the admission or corporate value of the Corporation.

In addition, none of the officers, directors, employees or consultants of the aforementioned firms is currently expected to be elected, appointed or employed as a director, officer or employee of the Corporation or any of its associates or affiliates, except that one employee of ERCE is expected to become an employee of the Corporation.

PricewaterhouseCoopers AG, Chartered Accountants, is the Corporation's auditor and such firm has advised they are independent in accordance with the auditor's rules of professional conduct in Canada. PricewaterhouseCoopers AG is a member of EXPERTsuisse – Swiss Expert Association for Audit, Tax and Fiduciary.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, where applicable, will be contained in the Corporation's information circular for its Annual Meeting of Shareholders that will involve the election of directors.

Additional financial information is provided in the Corporation's Audited Financial Statements and MD&A.

Additional information relating to the Group may be found under the Corporation's profile on SEDAR at www.sedar.com and on the Corporation's website at www.international-petroleum.com.

SCHEDULE A – FORM 51-101 F2 (ERCE)

Report on Reserves and Contingent Resources Data and Prospective Resources Data by Independent Qualified Resrves Evaluator or Auditor

To the board of directors of International Petroleum Corporation (the "Company"):

1. We have audited the Company's reserves data, certain contingent resources data and certain prospective resources data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2017, estimated using forecast prices and costs.

2. The reserves data, contingent resources data and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data, contingent resources data and prospective resources data based on our audit.

3. We carried out our audit in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company audited for the year ended March 31, 2017, and identifies the respective portions thereof that we have audited and reported on to the Company's management.

			Net Present Value of Future Net Revenue in USD (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of [Audit/Evaluation/ Review] Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
ERC Equipoise Ltd	December 31, 2017	Netherlands	18,535,864	0	0	18,535,864
ERC Equipoise Ltd	December 31, 2017	France	228,023,377	0	0	228,023,377
ERC Equipoise Ltd	December 31, 2017	Malaysia	318,297,360	0	0	318,297,360
Totals			**564,856,601**	**0**	**0**	**564,856,601**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have audited and reported on to the Company's management:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of [Audit/Evaluation] Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume	Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	ERC Equipoise Ltd	Dec 31, 2017	Netherlands	0	0	0	0
Development Pending Contingent Resources (2C)	ERC Equipoise Ltd	Dec 31, 2017	France	0	0	0	0
Development Pending Contingent Resources (2C)	ERC Equipoise Ltd	Dec 31, 2017	Malaysia	0	0	0	0

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of [Audit/Evaluation]	Location of Resources Other than Reserves	Risked Gross Working Interest Volume Oil (Mstb)	Risked Gross Working Interest Volume Gas (MMscf)
Prospective Resources (Best Estimate)	ERC Equipoise Ltd	Dec 31, 2017	Malaysia	1243.1	0.00
Contingent Resources Development Unclarified (2C)	ERC Equipoise Ltd	Dec 31, 2017	Malaysia	1035.0	0.00
Contingent Resources Development Unclarified (2C)	ERC Equipoise Ltd	Dec 31, 2017	France	7994.1	0.00

7. In our opinion, the reserves data, contingent resources data and prospective resources data respectively audited 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, contingent resources data and prospective resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

9. 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.

Executed as to our report referred to above:

ERC Equipoise Limited, London, United Kingdom, February 21, 2017

Paul Chernik

Paul Chernik, P.Eng
Director, ERC Equipoise Ltd.

SCHEDULE B – FORM 51-101 F2 (MCDANIEL)

Report on Reserves and Contingent Resources Data by Independent Qualified Reserves Evaluator of International Petroleum Corporation (the "Company")

To the Board of Directors of International Petroleum Corporation (the "Company"):

1. We have evaluated the Company's reserves and contingent resources data as at January 5, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at January 5, 2018 estimated using McDaniel 2018.01 forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources as at January 5, 2018.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended January 5, 2018, and identifies the respective portions thereof that we have evaluated and report on to the Company0s Board of Directors:

			Net Present Value of Future Net Revenue in USD (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates	January 5, 2018	Canada – CAD	-	830,079.6	-	830,079.6
McDaniel & Associates	January 5, 2018	Canada – USD	-	688,208.7	-	688,208.7

6. The following table sets forth the risked volume of contingent resources included in the Company's statement prepared in accordance with Revised Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's Board of Directors:

Classification	Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume
Contingent Resources - Development Unclarified	McDaniel & Associates	January 5, 2018	Canada	4,510 Mbbl Heavy Oil; 150,784 MMcf Conventional Natural Gas

7. In our opinion, the reserves and contingent resources 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 and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our report referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of report.

9 Because the reserves and contingent resources 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:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

Mike Verney

M. J. Verney, P. Eng.
Vice President

Calgary, Alberta, Canada
February 22, 2018

SCHEDULE C – FORM 51-101 F3

Form 51-101F3

Report of Management and Directors on Reserves Data and Other Information

Management of International Petroleum Corp. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This includes reserves data and other information such as contingent resources data or prospective resources data.

ERC Equipoise Ltd., an independent qualified reserves auditor, and McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, have, as applicable, audited, evaluated and reviewed the Corporation's reserves data, contingent resources data and prospective resources data. The reports of the independent qualified reserves auditor and the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves auditor and the independent qualified reserves evaluator;

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

(c) reviewed the reserves data, contingent resources data and prospective resources data, as applicable, with management and the independent qualified reserves auditor and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation'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 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 Forms 51-101F2, which are the reports of the independent qualified reserves auditor and the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data, as applicable; 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.

"Mike Nicholson"	*"Ryan Adair"*
Mike Nicholson, Chief Executive Officer	Ryan Adair, Vice President Reservoir Development
"Chris Bruijnzeels"	*"C. Ashley Heppenstall"*
Chris Bruijnzeels, Director	C. Ashley Heppenstall, Director

Date: March 30, 2018

SCHEDULE D – AUDIT COMMITTEE MANDATE

Audit Committee Mandate

As of May 11, 2017

1. Introduction

The Audit Committee (the "Committee" or the "Audit Committee") of International Petroleum Corporation (the "Company") is a committee of the board of directors (the "Board"). The Committee shall oversee the accounting and financial reporting practices of the Company and the audits of the Company's financial statements and exercise the responsibilities and duties set out in this Mandate.

2. Membership

Number of Members

The Committee shall be composed of three or more members of the Board.

Independence of Members

Each member of the Committee must be independent. "Independent" shall have the meaning, as the context requires, given to it in National Instrument 52-110 Audit Committees, as may be amended from time to time.
Chair

The members of the Committee shall elect a Chair of the Committee from among their number by majority vote of the full Committee membership. The Chair shall preside over all Audit Committee meetings, coordinate the Audit Committee's compliance with this Mandate, work with management to develop the Audit Committee's annual work-plan and provide reports of the Audit Committee to the Board.

Financial Literacy of Members

At the time of his or her appointment to the Committee, each member of the Committee shall have, or shall acquire within a reasonable time following appointment to the Committee, the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

Term of Members

The members of the Committee shall be appointed annually by the Board. Each member of the Committee shall serve at the pleasure of the Board until the member resigns, is removed, or ceases to be a member of the Board.

3. Meetings

Number of Meetings

The Committee may meet as many times per year as necessary to carry out its responsibilities.

Quorum

No business may be transacted by the Committee at a meeting unless a quorum of the Committee is present. A majority of members of the Committee shall constitute a quorum.

Calling of Meetings

The Chair, any member of the Audit Committee, the external auditor, the Chair of the Board, the Lead Director, the Chief Executive Officer or the Chief Financial Officer may call a meeting of the Audit Committee by notifying the Company's Corporate Secretary, who will notify the members of the Audit Committee. The Chair shall chair all Audit Committee meetings that he or she attends, and in the absence of the Chair, the members of the Audit Committee present may appoint a chair from their number for a meeting.

Minutes; Reporting to the Board

The Committee shall maintain minutes or other records of meetings and activities of the Committee in sufficient detail to convey the substance of all discussions held. Upon approval of the minutes by the Committee, the minutes shall be circulated to the members of the Board. However, the Chair may report orally to the Board on any matter in his or her view requiring the immediate attention of the Board.

Attendance of Non-Members

The external auditor is entitled to attend and be heard at, and shall be given reasonable notice of, each Audit Committee meeting. In addition, the Committee may invite to a meeting any officers or employees of the Company, legal counsel, advisors and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities. At least once per year, the Committee shall meet with the internal auditor and management in separate sessions to discuss any matters that the Committee or such individuals consider appropriate.

Meetings without Management

The Committee shall hold unscheduled or regularly scheduled meetings, or portions of meetings, at which management is not present.

Procedure

The procedures for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those applicable to meetings of the Board.

Access to Management

In discharging its duties and responsibilities, the Committee shall have unrestricted access to the Company's management and employees and to the relevant books, records and systems of the Company as it considers appropriate.

4. Duties and Responsibilities

The Committee shall have the functions and responsibilities set out below as well as any other functions that are specifically delegated to the Committee by the Board and that the Board is authorized to delegate by applicable laws and regulations. In addition to these functions and responsibilities, the Committee shall perform the duties required of an audit committee by any exchange upon which securities of the Company are traded, or any governmental or regulatory body exercising authority over the Company, as are in effect from time to time (collectively, the "Applicable Requirements").

Financial Reports

(a) General

The Audit Committee is responsible for overseeing the Company's financial statements and financial disclosures. Management is responsible for the preparation, presentation and integrity of the Company's financial statements and financial disclosures and for the appropriateness of the accounting principles and the reporting policies used by the Company. The external auditor is responsible for auditing the Company's annual consolidated financial statements and for reviewing the Company's unaudited interim financial statements.

(b) Review of Annual Financial Reports

The Audit Committee shall review the annual consolidated audited financial statements of the Company, the external auditor's report thereon and the related management's discussion and analysis of the Company's financial condition and results of operation ("MD&A"). After completing its review, if advisable, the Audit Committee shall approve and recommend for Board approval the annual financial statements and the related MD&A.

(c) Review of Interim Financial Reports

The Audit Committee shall review the interim consolidated financial statements of the Company, the external auditor's review report thereon, if any, and the related MD&A. After completing its review, if advisable, the Audit Committee shall either:

(i) formally approve (such approval to include the authorization for public release) or

(ii) recommend for Board approval,

the interim financial statements and the related MD&A. Unless determined otherwise by the Audit Committee in consultation with the Chair of the Board, the Audit Committee will formally approve for release the interim financial statements and related MD&A for the first and third quarters of each fiscal year, and will recommend for Board approval the interim financial statements and related MD&A for the second quarter of each financial year.

(d) Review Considerations

In conducting its review of the annual financial statements or the interim financial statements, the Audit Committee shall:

(i) meet with management and the external auditor to discuss the financial statements and MD&A;

(ii) review the disclosure in the financial statements;

(iii) review the audit report or review report prepared by the external auditor;

(iv) discuss with management, the external auditor and internal legal counsel, as requested, any litigation claim or other contingency that could have a material effect on the financial statements;

(v) review the accounting policies followed and critical accounting and other significant estimates and judgements underlying the financial statements as presented by management;

(vi) review any material effects of regulatory accounting initiatives or off-balance sheet structures on the financial statements as presented by management, including requirements relating to complex or unusual transactions, significant changes to accounting principles and alternative treatments under Canadian generally accepted accounting principles applicable to publicly accountable enterprises;

(vii) review any material changes in accounting policies and any significant changes in accounting practices and their impact on the financial statements as presented by management;

(viii) review management's report on the effectiveness of internal controls over financial reporting;

(ix) review the factors identified by management as factors that may affect future financial results;

(x) review results of the Company's audit committee whistleblowing program; and

(xi) review any other matters related to the financial statements that are brought forward by the external auditor or management or that are required to be communicated to the Audit Committee under accounting policies, auditing standards or Applicable Requirements.

(e) Review of Other Financial Disclosures

The Audit Committee shall review and, if advisable, recommend for Board approval financial disclosure in a prospectus or other securities offering document of the Company, press releases disclosing, or based upon, financial results of the Company, financial guidance provided to analysts or rating agencies or otherwise publicly disseminated and any other material financial disclosure.

(f) Review of Future-Oriented Financial Information or Financial Outlook

The Committee shall review and, if advisable, recommend for Board approval any material future oriented financial information or financial outlook and endeavour to ensure that there is a reasonable basis for drawing any conclusions or making any forecasts and projections set out in such disclosures.

Auditors

(a) General

The Audit Committee shall be responsible for oversight of the work of the external auditor, including the external auditor's work in preparing or issuing an audit report, performing other audit, review or attest services or any other related work. The external auditor will report directly to the Committee.

(b) Nomination and Compensation

The Audit Committee shall review and, if advisable, select and recommend for Board approval the external auditor to be nominated and the compensation of such external auditor. The Audit Committee shall have ultimate authority to approve all audit engagement terms and fees, including the external auditor's audit plan.

(c) Resolution of Disagreements

The Audit Committee shall resolve any disagreements between management and the external auditor as to financial reporting matters brought to its attention.

(d) Discussions with External Auditor

At least annually, the Audit Committee shall discuss with the external auditor such matters as are required by applicable auditing standards to be discussed by the external auditor with the Audit Committee.

(e) Audit Plan

At least annually, the Audit Committee shall review a summary of the external auditor's annual audit plan. The Audit Committee shall consider and review with the external auditor any material changes to the scope of the plan.

(f) Quarterly Review Report

The Audit Committee shall review a report prepared by the external auditor in respect of each of the interim financial statements of the Company.

(g) Independence of Auditors

At least annually, and before the external auditor issues its report on the annual financial statements, the Audit Committee shall: obtain from the external auditor a formal written statement describing all relationships between the external auditor and the Company; discuss with the external auditor any disclosed relationships or services that may affect the objectivity and independence of the external auditor; and obtain written confirmation from the external auditor that it is objective and independent within the meaning of the applicable Rules of Professional Conduct/Code of Ethics adopted by the provincial institute or order of chartered accountants to which the external auditor belongs and other Applicable Requirements. The Audit Committee shall take appropriate action to oversee the independence of the external auditor.

(h) Evaluation and Rotation of Lead Partner

At least annually, the Audit Committee shall review the qualifications and performance of the lead partner(s) of the external auditor and determine whether it is appropriate to adopt or continue a policy of rotating lead partners of the external auditor.

(i) Requirement for Pre-Approval of Non-Audit Services

The Audit Committee shall approve in advance any retainer of the external auditor to provide any non-audit service to the Company (together with all non-audit service fees) that it deems advisable in accordance with Applicable Requirements and Board-approved policies and procedures. The Audit Committee shall consider the impact of such service and fees on the independence of the external auditor. The Audit Committee may delegate pre-approval authority to a member of the Audit Committee. The decisions of any member of the Audit Committee to whom this authority has been delegated must be presented to the full Audit Committee at its next scheduled Audit Committee meeting.

(j) Approval of Hiring Policies

The Audit Committee shall review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company and the Committee shall be responsible for any specified reporting and pre-approval functions thereunder.

(k) Communication with Internal Auditor

The internal auditor shall report regularly to the Committee. The Committee shall review with the internal auditor any problem or difficulty the internal auditor may have encountered including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to management prepared by the internal auditing department and management's responses thereto. The Committee shall periodically review and approve the mandate, plan, budget and staffing of the internal audit department. The Committee shall direct management to make changes it deems advisable in respect of the internal audit function.

The Committee shall review the appointment, performance and replacement of the senior internal auditing executive and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(l) Financial Executives

The Committee shall review and discuss with management the appointment of key financial executives and recommend qualified candidates to the Board, as appropriate.

<u>Internal Controls</u>

(a) General

The Audit Committee shall review the Company's system of internal controls.

(b) Establishment, Review and Approval

The Audit Committee shall require management to implement and maintain appropriate systems of internal controls in accordance with Applicable Requirements, including internal controls over financial reporting and disclosure and to review, evaluate and approve these procedures. At least annually, the Audit Committee shall consider and review with management and the external auditor:

(i) the effectiveness of, or weaknesses or deficiencies in: the design or operation of the Company's internal controls (including computerized information system controls and security); the overall control environment for managing business risks; and accounting, financial and disclosure controls (including, without limitation, controls over financial reporting), non-financial controls, and legal and regulatory controls and the impact of any identified weaknesses in internal controls on management's conclusions;

(ii) any significant changes in internal controls over financial reporting that are disclosed, or considered for disclosure, including those in the Company's periodic regulatory filings;

(iii) any material issues raised by any inquiry or investigation by regulators;

(iv) the Company's fraud prevention and detection program, including deficiencies in internal controls that may impact the integrity of financial information, or may expose the Company to other significant internal or external fraud losses and the extent of those losses and any disciplinary action in respect of fraud taken against management or other employees who have a significant role in financial reporting; and

(v) any related significant issues and recommendations of the external auditor together with management's responses thereto, including the timetable for implementation of recommendations to correct weaknesses in internal controls over financial reporting and disclosure controls.

Compliance with Legal and Regulatory Requirements

The Audit Committee shall review reports from the Company's Corporate Secretary and other management members on: legal or compliance matters that may have a material impact on the Company; the effectiveness of the Company's compliance policies; and any material communications received from regulators. The Audit Committee shall review management's evaluation of and representations relating to compliance with specific applicable law and guidance, and management's plans to remediate any deficiencies identified.

Audit Committee Whistleblowing Procedures

The Audit Committee shall establish procedures for (a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters. Any such complaints or concerns that are received shall be reviewed by the Audit Committee and, if the Audit Committee determines that the matter requires further investigation, it will direct the Chair of the Audit Committee to engage outside advisors, as necessary or appropriate, to investigate the matter and will work with management and the general counsel to reach a satisfactory conclusion.

Audit Committee Disclosure

The Audit Committee shall prepare, review and approve any audit committee disclosures required by Applicable Requirements in the Company's disclosure documents.

Delegation

The Audit Committee may, to the extent permitted by Applicable Requirements, designate a sub-committee to review any matter within this mandate as the Audit Committee deems appropriate.

5. Outside Advisors

The Committee shall have the authority to retain external legal counsel, consultants or other advisors to assist it in fulfilling its responsibilities and to set and pay the respective compensation for these advisors. The Company shall provide appropriate funding, as determined by the Committee, for the services of these advisors.

6. No Rights Created

This Mandate is a statement of broad policies and is intended as a component of the flexible governance framework within which the Audit Committee functions. While it should be interpreted in the context of all applicable laws, regulations and listing requirements, as well as in the context of the Company's articles, it is not intended to establish any legally binding obligations.

7. Mandate Review

The Committee shall review and update this Mandate annually and present it to the Board for approval.

DIRECTORS

Lukas H. Lundin
Director, Chairman
Geneva, Switzerland

Mike Nicholson
Director, President and Chief Executive Officer
Geneva, Switzerland

Chris Bruijnzeels
Director
Geneva, Switzerland

C. Ashley Heppenstall
Lead Director
Hong Kong

Donald Charter
Director
Toronto, Ontario

Torstein Sanness
Director
Oslo, Norway

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Daniel Fitzgerald
Vice President Operations
Geneva, Switzerland

Ryan Adair
Vice President Reservoir Development
Geneva, Switzerland

INVESTOR RELATIONS

Rebecca Gordon
VP Corporate Planning and Investor Relations
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INDEPENDENT AUDITORS

PricewaterhouseCoopers AG Geneva, Switzerland

TRANSFER AGENT

Computershare Trust Company of Canada Calgary, Alberta and Toronto, Ontario

MEDIA RELATIONS

Robert Eriksson Stockholm, Sweden

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ First North Exchange Trading Symbol: IPCO

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