AIF 2024

International Petroleum Corporation

Annual Information Form

For the year ended December 31, 2024

Dated March 24, 2025

Annual Information Form
For the year ended December 31, 2024

Contents

Schedules

GLOSSARY OF TERMS

"**AIF**" or "**Annual Information Form**" means this Annual Information Form of IPC prepared for the year ended December 31, 2024 and dated March 24, 2025.

"**Audited Financial Statements**" means the audited consolidated financial statements of the Corporation for the year ended December 31, 2024.

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

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

"**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.

"**MD&A**" means the Management's Discussion and Analysis of the Corporation for the year ended December 31, 2024.

"**Nasdaq Stockholm**" means the Nasdaq Stockholm 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.

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

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

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
MCAD	million CAD
EUR or €	Euro
USD or US$	United States dollar
MUSD	million USD
MYR	Malaysian Ringgit
FPSO	Floating production, storage and offloading vessel
PSC	Production sharing contract

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
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion cubic feet
C5	Condensate
CO_2e	Carbon dioxide equivalents, including carbon dioxide, methane and nitrous oxide
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced oil recovery
GJ	Gigajoules
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
MMbtu	Million British thermal units
Mcf	Thousand cubic feet
Mcfpd	Thousand cubic feet per day
MMcf	Million cubic feet
MW	Mega watt
MWh	Mega watt per hour
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage
WTI	West Texas Intermediate
WCS	Western Canadian Select

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 made, 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:

- 2025 production ranges (including total daily average production), production composition, cash flows, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC’s current business plans and assumptions regarding the business environment, which are subject to change;
- IPC’s financial and operational flexibility to navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC’s intention and ability to continue to implement strategies to build long-term shareholder value;
- The ability of IPC’s portfolio of assets to provide a solid foundation for organic and inorganic growth;
- The continued facility uptime and reservoir performance in IPC’s areas of operation;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven prices and net present value;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC’s ability to benefit from any such improvements;
- The ability to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire further Common Shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC’s shareholders as a result of the NCIB;
- The ability of IPC to implement further shareholder distributions in addition to the NCIB;
- IPC’s ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC’s continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC’s ability to identify and complete future acquisitions;
- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, tariffs, and ongoing projects and their expected completion; and
- Future drilling and other exploration and development activities.

Statements relating to "reserves" and "contingent 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. See also “Reserves and Resources Advisory”.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: the potential impact of tariffs announced in March 2025 by the U.S. and Canadian governments and that other than the tariffs that have been announced, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; 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; our ability to maintain our existing credit ratings; our ability to achieve our performance targets; 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 and that we will be able to implement our standards, controls, procedures and policies in respect of any acquisitions and realize the expected synergies on the anticipated timeline or at all; 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; our intention to complete share repurchases under our normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of our common shares, and compliance with respect to applicable limitations under securities laws and regulations and stock exchange policies; 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:

- General global economic, market and business conditions;
- 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 fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental and climate-related risks;
- Competition;
- Innovation and cybersecurity risks related to our systems, including our costs of addressing or mitigating such risks;
- The ability to attract, engage and retain skilled employees;
- 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;
- Geopolitical conflicts, including the war between Ukraine and Russia and the conflict in the Middle East, and their potential impact on, among other things, global market conditions;
- Political or economic developments, including, without limitation, the risk that (i) one or both of the U.S. and Canadian governments imposes or increases the rate or scope of tariffs announced in March 2025, or imposes new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs to be imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Corporation; 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. See also "Risk Factors".

References may be made in this AIF to "free cash flow" (FCF), "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 IFRS and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of FCF, OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that FCF, 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 MD&A and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR+ website (www.sedarplus.ca) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCES 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 and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2024, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, 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 Sproule's December 31, 2024 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2024 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in "Statement of Reserves Data and Other Oil and Gas Information – Part III Pricing Assumptions" below. These price forecasts are as at December 31, 2024 and may not be reflective of current and future forecast commodity prices.

The product types comprising the 2P reserves and contingent resources described in this AIF are contained in "Statement of Reserves Data and Other Oil and Gas Information" below. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil and bitumen 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.

Each of the reserves categories reported (proved and probable) may be divided into developed and undeveloped categories. "Developed reserves" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing. "Developed producing reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty. "Developed non-producing reserves" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown. "Undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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 percent 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 either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. 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. Where risked resources are presented, they have been adjusted based on the chance of development by multiplying the unrisked values by the Chance of Development.

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 Corporation's control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in this AIF.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE have been aggregated 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 and resources. 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 reserves and resources evaluations will be attained and variances could be material.

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

Supplemental Information regarding Product Types

The following table is intended to provide supplemental information about the product type composition of IPC's net average daily production figures provided in this document:

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
December 31, 2024	24.3	7.1	95.9 MMcf (16.0 Mboe)	47.4
December 31, 2023	25.7	6.6	103.8 MMcf (17.3 Mboe)	49.6
Year ended				
December 31, 2024	23.9	7.7	95.1 MMcf (15.8 Mboe)	47.4
December 31, 2023	25.8	8.1	102.8 MMcf (17.1 Mboe)	51.1

This AIF also makes reference to IPC's forecast total average daily production of 43,000 to 45,000 boepd for 2025. IPC estimates that approximately 52% of that production will be comprised of heavy oil, approximately 15% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

INTRODUCTION

The information set out in this AIF is stated as at December 31, 2024, unless otherwise indicated.

Reserves and contingent resources included in the reports prepared by Sproule and ERCE have been aggregated in this document by IPC as at December 31, 2024.

The MD&A and the Audited Financial Statements are incorporated by reference and may be accessed on the SEDAR+ website at www.sedarplus.ca under the Corporation's profile or on IPC's website at www.international-petroleum.com. See "**Cautionary Statement Regarding Forward-Looking Information**" and in particular, note that forward-looking statements speak only as of the date made, unless otherwise indicated, and IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

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

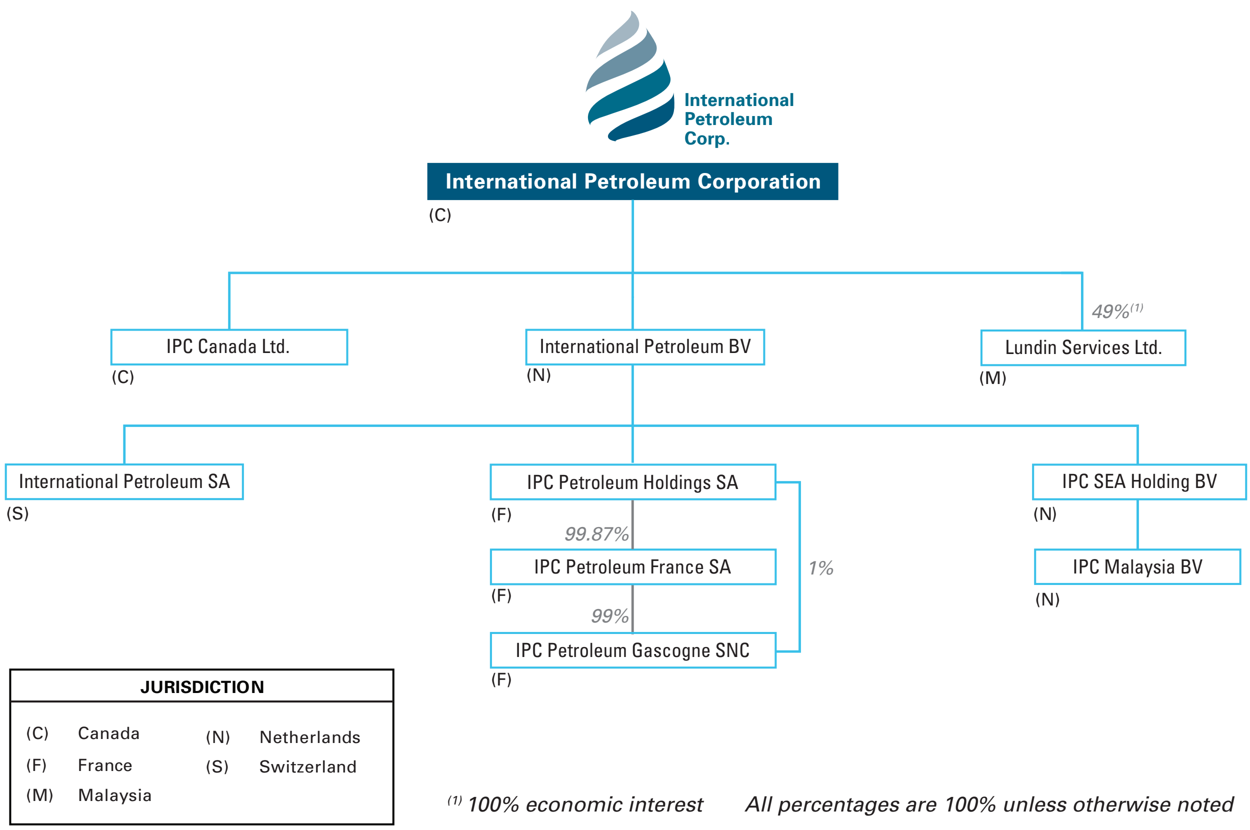
CORPORATE STRUCTURE

The full corporate name of the Corporation is International Petroleum Corporation. The Corporation's head office is located at Suite 2800, 1055 Dunsmuir Street, Vancouver, British Columbia, Canada V7X 1L2 and the registered and records office is located at Suite 3500, 1133 Melville Street, Vancouver, British Columbia, Canada V6E 4E5.

IPC is a reporting issuer in British Columbia, Alberta, Saskatchewan, Manitoba and Ontario. The Common Shares trade on the TSX and Nasdaq Stockholm 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

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 and France with exposure to growth opportunities. IPC is focused on delivering operational excellence, demonstrating financial resilience, maximizing the value of IPC's resource base, and targeting growth organically and through acquisition.

The following provides a summary of how IPC's business has developed over the last three years.

Year ended December 31, 2022

In January 2022, IPC announced that international credit rating agencies Moody's and S&P Global Ratings assigned corporate credit ratings to IPC. Moody's assigned a credit rating of B1 with a stable outlook and S&P Global Ratings assigned a credit rating of B with a stable outlook.

In January 2022, IPC announced that it successfully completed a private placement of USD 300 million of senior unsecured bonds. The bonds have a tenor of five years and a fixed coupon rate of 7.25 percent per annum, with interest payable in semi-annual instalments. The bond issue was rated B+ by S&P Global Ratings and B1 by Moody's. IPC used a portion of the proceeds of the bond to fully repay and cancel existing reserve-based lending facilities and, at the same time, IPC put in place a new CAD 75 million revolving credit facility for financial flexibility in Canada.

In February 2022, IPC announced its 2022 capital expenditure budget of USD 127 million and its 2022 production guidance of between 46,000 and 48,000 boepd. IPC also announced its 2021 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 270 MMboe and 1,410 MMboe. IPC's net debt was confirmed as USD 94 million as at December 31, 2021. IPC's 2022 capital expenditure budget includes the commencement of investment at Onion Lake Thermal on the next sustaining Pad L as well as further infill drilling, Suffield oil N2N drilling, Phase 1 development at the Ferguson asset and Blackrod FEED studies as well as continued production from Well Pair 3 in Canada. IPC also stated its plans to complete the A15 side-track well and ESP pump upsizing campaign in Malaysia as well as to start the Phase 1 development of the Villeperdue West project in France. IPC also stated that based on current business plans and assumptions, IPC plans to distribute to shareholders up to 40% of the free cash flow generated by IPC above achieved average Brent oil prices of USD 55 per barrel, provided that IPC's net debt to EBITDA ratio is at or below 1 time.

In May 2022, IPC announced its intention to launch a substantial issuer bid (SIB) to purchase of cancellation up to approximately USD 100 million of Common Shares. IPC also announced the completion of drilling operations on the A15 side-track well and three well pump upgrades at the Bertam field, Malaysia. IPC also reported net debt of USD 42 million as at March 31, 2022.

In June 2022, IPC announced the results of the SIB under which the Corporation purchased and cancelled 8,258,064 Common Shares at a purchase price of CAD 15.50 per Common Share, for an aggregate purchase price of approximately CAD 128 million or USD 100 million as at the expiry date of the Offer. These Common Shares represented approximately 5.5% of the issued and outstanding Common Shares when the SIB was commenced.

IPC announced in August 2022 that its full year 2022 average net production forecast was expected to be towards the upper end of the guidance range of 46,000 to 48,000 boepd. IPC also reported net cash of USD 14 million as at June 30, 2022.In addition, the 2022 capital expenditure budget was increased to USD 170 million from USD 127 million, accelerating projects and adding additional capital activity in Canada and France given the strong oil and gas prices. IPC also published its third Sustainability Report, detailing the Corporation's ESG performance and aligned with the Global Reporting Initiative (GRI) standards and the Task Force on Climate-Related Financial Disclosures (TCFD).

In November 2022, IPC announced that its full year 2022 average net production forecast was expected to be above the upper end of the guidance range of 46,000 to 48,000 boepd. IPC also reported net cash of USD 89 million as at September 30, 2022.

In December 2022, IPC announced the renewal of the NCIB under which IPC was authorized to repurchase through the facilities of the TSX and Nasdaq Stockholm, up to approximately 9.3 million Common Shares, over the twelve-month period to December 2023.

In December 2022, IPC announced the agreement to extend the Bertam field PSC by ten years to August 2035.

IPC announced during January to December 2022 that following the cancellation of an aggregate of 10,112,042 Common Shares repurchased by IPC under the NCIB over January to December 2022, in addition to the 8,258,064 Common Shares purchased and cancelled under the SIB, the total number of issued and outstanding Common Shares was 136,827,999 Common Shares as at end December 2022. This represented a reduction of approximately 11.8% of the number of issued and outstanding Common Shares from end 2021 to end 2022.

Year ended December 31, 2023

In February 2023, IPC announced the acquisition of oil and gas assets in the Suffield area of southern Alberta including total 2P reserves of 15.9 MMboe as at December 31, 2022. In March 2023, IPC announced the completion of this acquisition.

In February 2023, IPC announced that IPC's full year 2022 average net production was 48,600 boepd. IPC also announced its 2023 capital expenditure budget of USD 365 million and its 2023 production guidance of between 48,000 and 50,000 boepd. IPC also announced its 2022 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 487 MMboe (including 2P reserves in respect of the Suffield area assets acquired in March 2023) and 1,162 MMboe. IPC's net cash was reported as USD 175 million as at December 31, 2022. IPC confirmed the sanction of the development of Phase 1 of the Blackrod project, Alberta, Canada. IPC also stated that its intention is to continue to purchase and cancel Common Shares under the NCIB in 2023.

In May 2023, IPC announced quarterly average net production of approximately 52,800 boepd for the first quarter of 2023. IPC announced that its full year 2023 average net production forecast was expected to be at the upper end of the guidance range of 48,000 to 50,000 boepd. IPC also reported net cash of USD 67 million as at March 31, 2023.

IPC announced in August 2023 that its full year 2023 average net production forecast was expected to exceed the upper end of the guidance range of 48,000 to 50,000 boepd. IPC also reported net cash of USD 64 million as at June 30, 2023. In addition, IPC reported that it continued to progress the development of Phase 1 of the Blackrod project in Canada, including signing the engineering, procurement and fabrication contract for the Central Processing Facility. IPC also published its fourth annual Sustainability Report providing details on IPC's approach to sustainability, highlighting specific initiatives, and measurable goals and targets related to the key focus areas. IPC also published its first standalone Task Force on Climate-Related Financial Disclosures (TCFD) Report, aligned with the recommendations of the TCFD and demonstrating IPC's commitment to addressing climate-related risks and opportunities to its business.

In September 2023, IPC announced the successful completion of the tap issue of USD 150 million of senior unsecured bonds under IPC's existing 7.25% senior unsecured bonds. IPC confirmed that the bonds are rated B+ by S&P Global Ratings and B1 by Moody's.

In October 2023, IPC announced that its full year 2023 average net production forecast was expected to exceed an average of 50,000 boepd for the full year 2023, above the high end of the guidance range. IPC also reported net cash of USD 83 million as at September 30, 2023. IPC further reported that IPC continued to progress the development of Phase 1 of the Blackrod project in Canada. In addition, IPC announced that William Lundin will assume the role of President and CEO from January 1, 2024 as Mike Nicholson retired from executive management, with Mr. Nicholson continuing as a member of the Board of Directors of IPC and Mr. Lundin joining as a new member of the Board of Directors of IPC on January 1, 2024.

In November 2023, IPC announced the appointment of Deborah Starkman as a new member of the Board of Directors of IPC.

In December 2023, IPC announced the renewal of the NCIB under which IPC was authorized to repurchase through the facilities of the TSX and Nasdaq Stockholm, up to approximately 8.3 million Common Shares, over the twelve-month period to December 2024.

IPC announced during January to December 2023 that following the cancellation of an aggregate of 9,835,933 Common Shares repurchased by IPC under the NCIB over January to December 2023, the total number of issued and outstanding Common Shares was 126,992,066 Common Shares as at end December 2023. This represented a reduction of approximately 7.2% of the number of issued and outstanding Common Shares from end 2022 to end 2023.

Year ended December 31, 2024

In February 2024, IPC announced that IPC's full year 2023 average net production was 51,100 boepd. IPC also announced that following the decision in Q1 2023 to develop Phase 1 of the Blackrod project, work on the project had progressed in line within the overall schedule and budget to first oil in late 2026. Key events in 2023 included signing of the engineering, procurement and fabrication contract for the Central Processing Facility and advancement of facility engineering and fabrication works, access road expansion and site civil preparation works, and drilling operations. In addition, IPC reported its 2024 capital and decommissioning expenditure budget of USD 437 million, including USD 362 million relating to continued development of Phase 1 of the Blackrod project, and its 2024 production guidance of between 46,000 and 48,000 boepd. IPC also announced its 2023 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 468 MMboe and 1,145 MMboe. IPC's net cash was reported as USD 58 million as at December 31, 2023. IPC confirmed its intention to complete the NCIB by purchasing and cancelling a further 6.5 million shares up to the end of that program in early December 2024.

In May 2024, IPC announced quarterly average net production of approximately 48,800 boepd for the first quarter of 2024. IPC also reported net debt of USD 61 million as at March 31, 2024.

IPC announced in July 2024 that its quarterly average net production for the second quarter was approximately 48,400 boepd. IPC also reported net debt 88 million as at June 30, 2024. IPC also published its fifth annual Sustainability Report providing details on IPC's approach to sustainability.

In November 2024, IPC announced that that its quarterly average net production for the third quarter was approximately 45,000 boepd. IPC also reported net cash of USD 157 million as at September 30, 2024.

In December 2024, IPC announced the renewal of the NCIB under which IPC was authorized to repurchase through the facilities of the TSX and Nasdaq Stockholm, up to approximately 7.5 million Common Shares, over the twelve-month period to December 2025.

IPC announced during January to December 2024 that following the cancellation of an aggregate of 7,822,595 Common Shares repurchased by IPC under the NCIB over January to December 2024, the total number of issued and outstanding Common Shares was 119,169,471 Common Shares as at end December 2024. This represented a reduction of approximately 6.2% of the number of issued and outstanding Common Shares from end 2023 to end 2024.

Subsequent to the year ended December 31, 2024

In February 2025, IPC announced that IPC's full year 2024 average net production was 47,400 boepd. IPC also announced that work on Phase 1 of the Blackrod project continues to progress in line with schedule and budget, with forecast first oil in late 2026. In respect of the Blackrod project as at December 31, 2024, all major third-party contracts have been executed and construction is advancing according to plan, including construction of the central processing facility (CPF) and well pad facilities, finalization of the midstream agreements for the input fuel gas, diluent and oil blend pipelines, and advancement of drilling operations. As at the end of 2024, over two-thirds of the forecast Blackrod Phase 1 development capital expenditure of USD 850 million has been spent since project sanction in early 2023. In addition, IPC reported its 2025 capital and decommissioning expenditure budget of USD 320 million, including USD 230 million relating to continued development of the Blackrod project, and its 2025 production guidance of between 43,000 and 45,000 boepd. IPC also announced its 2024 year-end 2P reserves and best estimate contingent resources (unrisked) of respectively 493 MMboe and 1,107 MMboe. IPC's net debt was reported as USD 209 million as at December 31, 2024.

IPC announced during January to March 2025 that following the cancellation of an aggregate of 2,759,903 Common Shares repurchased by IPC under the NCIB and other applicable exemptions over January to February 2025, the total number of issued and outstanding Common Shares was 116,409,568 Common Shares, of which IPC held 1,033,098 Common Shares in treasury, as at March 21, 2025.

Significant Acquisitions in the year ended December 31, 2024

IPC did not complete any acquisitions requiring the filing of a business acquisition report under applicable Canadian securities regulations during the year ended December 31, 2024.

DESCRIPTION OF THE BUSINESS

Summary

As at December 31, 2024, the Group operated its produced volumes in Canada, Malaysia and France (Paris Basin) and owned non-operated interests in France (Aquitaine Basin). As operator of its oil and gas assets, 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.

For the full year 2024, IPC reported average daily production of 47.4 Mboepd (50% heavy crude oil, 16% light and medium crude oil and 33% natural gas).

During 2024, IPC's operating cash flow was approximately USD 342 million and IPC's total year end net debt was USD 209 million.

As at the end of December 2024, IPC's 2P reserves were 493 MMboe, with a reserves life index of 31 years. This represents a reserves replacement ratio of approximately 251% compared to year-end 2023. The product types comprising the 2P reserves described in this AIF are contained in "Statement of Reserves Data and Other Oil and Gas Information" below. See also "Supplemental Information regarding Product Types" above.

In addition, IPC had best estimate contingent resources (unrisked) as at the end of December 2024 of 1,107 MMboe.

IPC's oil and gas assets in Canada are located in Alberta and Saskatchewan. In January 2018, IPC completed the acquisition of the Suffield area oil and gas assets in Alberta, Canada. In December 2018, IPC completed the acquisition of BlackPearl Resources Inc., including the interests in the Blackrod, Onion Lake and Mooney projects in Alberta and Saskatchewan, Canada. In March 2020, IPC completed the acquisition of the interests in the Ferguson assets in Alberta, Canada. In March 2023, IPC completed the acquisition of further oil and gas assets in the Suffield area.

IPC's oil and gas asset in Malaysia is a 100% working interest in the offshore Bertam field. 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 licenses in the Paris Basin (operated by the Group) and the Aquitaine Basin (non-operated).

Description of the Group's Oil and Gas Assets

The following is a description of the properties comprising the Group's oil and gas assets in Canada, Malaysia and France. The following property descriptions are as at December 31, 2024 unless otherwise indicated.

Canada

IPC's oil and gas assets in Canada are located in Alberta and Saskatchewan. The Suffield area oil and gas assets and the Ferguson oil asset are located in southern Alberta. IPC's principal assets in northern Alberta and Saskatchewan are the Blackrod and Onion Lake projects which are heavy crude oil assets applying conventional and steam assisted development methods.

2024 Summary

Working interest production from IPC's Canadian assets was 41.2 Mboepd in 2024.

In 2024, the Blackrod Phase 1 development project progressed in line with schedule and budget. Process facility fabrication remained on track supporting critical equipment site installation which continued to progress in line with plan. Access road upgrades were completed and third-party transport pipeline installation progressed on schedule. Production well pad drilling continued and was ahead of schedule as at year end 2024. At Onion Lake Thermal, three production sustaining Pad L well pairs were brought online in 2024. At Suffield, eight Ellerslie formation production wells were brought online in 2024. At Ferguson, IPC drilled five oil production wells during 2024.

Blackrod

Asset Overview and Production Operations

Blackrod is an in situ (SAGD) heavy oil project located south of Fort McMurray about 20 kilometres north of Wandering River, in the Athabasca region of northern Alberta. IPC holds a 100% working interest in the project. The Blackrod thermal pilot project began in 2011, with three pilot well pairs having been drilled.

Blackrod Phase 1 Development

In 2024, IPC advanced the development of Phase 1 of the Blackrod project. Development capital expenditure to first oil is estimated at USD 850 million. First oil of the Phase 1 development is estimated to be in late 2026, with forecast net production of 30,000 bopd by 2028. The Blackrod Phase 1 development targets 259 million barrels of 2P reserves. IPC invested USD 591 million of capital expenditure in the Blackrod Phase 1 project by the end of 2024.

Project activities for the multi-year Phase 1 development progressed in line with schedule and budget during 2024. Significant progress was made across all key scopes of the project including but not limited to: detailed engineering, procurement, fabrication, drilling, construction, third party transport pipelines, commissioning and operations planning. Site health and safety control has been excellent with zero lost time incidents since commercial development activities commenced. Statements in this AIF relating to the development of the Blackrod project, including estimates of resources volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values are forward-looking statements. See "**Cautionary Statement regarding Forward-Looking Statements**", "**Reserves and Resources Advisory**" and "**Risk Factors**".

IPC holds a 100% working interest in approximately 87 net sections (22,184 net hectares) of in situ oil sands leases in the Blackrod area.

Geological Overview

The geological formation of interest at Blackrod is the Cretaceous Lower Grand Rapids (LGR) at a depth of approximately 300 metres. The thick, laterally extensive, stacked shoreface sandstones of the LGR formation are interpreted to have been deposited in a shallowing-upward, marginal-marine environment. At Blackrod, the LGR formation consists of three para-sequences which have been informally named from top to bottom as LGR 1, LGR 2 and LGR 3. Each para-sequence ranges in thickness from 5 metres to 30 metres, with the thickest and cleanest parasequence being observed in LGR 1. It is this uppermost para-sequence that is bitumen bearing.

The depositional setting allowed for the creation of a large, regionally consistent LGR 1 reservoir with the reservoir ranging in thickness from 8 to 28 metres. Bitumen saturation within the LGR 1 reservoir varies between 50% and 75%, averaging approximately 60%. Reservoir permeability averages 3 Darcy. The viscosity of the bitumen ranges from approximately 150,000 centipoise at the top of the reservoir, increasing with depth to greater than 1,000,000 centipoise with API gravity ranging between 8° and 10°.

Onion Lake Thermal

Asset Overview and Production Operations

Onion Lake Thermal is a heavy oil property located in the Lloydminster area in Saskatchewan.

Oil is produced from the Onion Lake Thermal assets utilising a modified steam assisted gravity drainage (SAGD) technique: steam is injected in the direction of the reservoir in a matrix type formation generating steam heat chambers around the horizontal sections of strategically placed production wells, aiming to maximise steam oil ratio efficiency, production rates and ultimate recovery. The production is collected in a common pipeline system and routed to processing facilities.

Through sustaining production well pad development and facility capacity optimization, IPC continues to focus on maximising production delivery at the Onion Lake Thermal asset. In 2023, production sustaining well Pad L was brought online with a phased well ramp-up plan. By the end of 2024, seven out of eight Pad L well pairs had been brought on to production.

IPC is operator of the Onion Lake Thermal asset holding a 100% working interest.

Geological Overview

The geological formation of interest is the Cretaceous Cummings formation. The Cummings reservoir is divided into a Lower and Upper sequence throughout Onion Lake.

In the Onion Lake area, the Lower Cummings formation occurs at approximately 625 metres true vertical depth (TVD) and consists of a variable succession of blocky, clean sandstones interlaminated with siltstones, mudstones and breccias that were deposited in an overall transgressive estuarine environment. The stacked estuarine deposits have coalesced to form vertically continuous sand bodies that are oil saturated and comprise the main reservoir target for thermal development. The Lower Cummings is 75% to 90% oil saturated and has an average API gravity of 10.5º. Permeability ranges from 3 to 10 Darcy, net pay ranges from 8 to 25 metres and viscosities average about 50,000 centipoise.

The Upper Cummings Reservoir at Onion Lake is interpreted to have been deposited in a tidally influenced marginal marine shoreface environment. Separating the Upper Cummings from the Lower Cummings is a regional shale, interpreted to be a flooding surface. The Upper Cummings is 65% to 75% oil saturated and oil quality is approximately 11° API. Permeability ranges from 1 to 4 Darcy, net pay ranges from 5 to 12 metres and viscosities average about 40,000 centipoise.

Suffield Area

Asset Overview and Production Operations

The Suffield area assets are conventional oil and gas assets held over a large land position which includes shallow gas and oil rights. Production and reserves from the assets come from conventional shallow oil and gas wells. These are low decline producing fields with further development opportunities including infill drilling, enhanced oil recovery (EOR) projects, well stimulation and facility optimizations. These assets include the oil and gas interests acquired in the Brooks area in 2023.

Oil is produced from the Suffield area assets using both enhanced (EOR) and 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.

Gas production in the Suffield area is via shallow wells producing from multiple formations. The wells produce into a network of gas pipelines with a number of compressor stations.

IPC continues to successfully offset historic field production decline rates through conventional oil well drilling, EOR projects and a multi-year gas optimization program focussing on well swabbing activity and production zone well recompletions. During 2024, eight wells on the Ellerslie formation were drilled, completed and brought on production.

IPC is operator of the Suffield area oil and gas assets, with a 100% working interest in the oil assets and 99.7% working interest (on a well-count basis) in the gas assets.

Geologic Overview

The main oil producing horizon is the Cretaceous age Glauconitic (Mannville group) sand. The sand was deposited in a shoreline / Aeolian environment and is generally of very high reservoir quality. Reservoir depth is approximately 1,000 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 Mannville Ellerslie, and Lower Mannville Detrital.

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.

Ferguson

Asset Overview and Production Operations

The Ferguson asset is a light oil field in Southern Alberta. The core pool produces approximately 30º API oil and is under a gas injection EOR scheme. During 2024, five wells were drilled, completed and brought on production.

IPC is operator of the Ferguson asset holding a 100% working interest.

Geological Overview

The Banff sand is the primary formation producing at Ferguson. The Banff-Exshaw-BV B Pool is the lower portion of the Mississippian formation. The depositional setting is a mixed carbonate-siliciclastic shelf with a distally-steepened carbonate ramp. The sand is deposited within the graded shelf as a regressive shoreface prograding west toward the basin. The Banff sand has good caprock seal and base rock. It is capped by a tight limestone and various shales and silts above the limestone. The Banff sand base is a thin shale and then a thick, tight dolomitic siltstone. Below the dolomitic siltstone is the Devonian Exshaw shale.

Canada Other

In addition, IPC holds conventional heavy oil assets at Onion Lake Primary and Mooney.

Canada Abandonment Obligations

Abandonment consists of permanent capping of 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 expenditure budget. The Group follows the applicable Saskatchewan/Alberta regulations and reports regularly to the appropriate regulator on its abandonment activities at all operational sites. On this basis, uneconomic wells and/or non-producing wells are regularly abandoned as a part of ongoing business.

IPC is committed to responsibly managing its abandonment risks and liabilities in Canada, in compliance with applicable regulations. In determining abandonment strategy and budget for all its assets in Canada, IPC takes into account several factors with respect to the asset, including remaining economic life, safety and environment risks, regulatory compliance, and cost and time efficient abandonment operations.

Malaysia

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 100% working interest.

2024 Summary

Working interest annual production from the Bertam field on Block PM307 during 2024 was 3.8 Mboepd.

In 2024, field development studies progressed in line with expectations as IPC matures the remaining undeveloped potential of the Bertam field. In addition, the A21 infill well was matured from contingent resources to reserves in 2024.

Bertam Field

Asset Overview and Production Operations

The Bertam field is located 175 kilometres offshore to the east of Peninsular Malaysia, at a water depth of about 74 metres. The field is a low relief, approximately 15 square kilometers, four-way closure. Maximum oil column is in the order of 20 to 25 metres. Reservoir depth is approximately 1,600 metres below sea level.

The reservoir recovery mechanism is moderate to strong aquifer drive. Since the reservoir is undersaturated with no gas cap, the wells require artificial lift using electric submersible pumps (ESP). Oil produced from the Bertam field is with an API gravity of 37°.

The wells are tied back to the FPSO Bertam where separation and storage take place.

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 (excluding planned shutdowns).

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 to 25% and permeability is 80 to 300 millidarcies.

Malaysia 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 cleaned and returned to the Group as owner of the vessel. 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.

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 fields in which IPC holds a 50% non-operated working interest.

2024 Summary

Net production in France during 2024 was 2.4 Mboepd.

In 2024, IPC continued to mature future development projects in France, with the next phase of production well targets matured and ready for sanction decision at IPC's discretion.

France – Paris Basin

Asset Overview and Production Operations

The French operations are an asset base consisting of ten oil field licenses and one exploration permit 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 nine of the ten producing fields.

Most production wells in the Paris Basin are activated by beam pumps. The injection wells are functioning with surface pumps. Oil is produced with a 35° API gravity. During 2024, IPC purchased a further interest in the Fontaine au Bron asset, which is situated adjacent to the Villeperdue West asset. The asset is on production with further development plans being matured.

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 Villeperdue production centre where separation takes place. Produced water is reinjected into the reservoirs for pressure support. Oil is transported by truck to sales points.

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.

France – The Aquitaine Basin

Asset Overview and Production Operations

The Group has 50% non-operated working interests in five production licenses in the Aquitaine Basin.

Oil is produced via water-flood drive and ranges from 28 to 34° API gravity. All producing wells are activated by electric submersible pumps. Injector wells are equipped with surface injection pumps.

Oil and water produced from Les Pins and Les Mimosas is transported by a pipeline network to Les Arbousiers where water/oil separation takes place, then the oil is sent via a pipeline to Les Mimosas where all the oil is trucked to the third party owned and operated Cazaux field.

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.

France 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 reports 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.

Employees

As of December 31, 2024, IPC had a total of 297 employees located in Canada, Malaysia, France and Switzerland 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 Canada, Malaysia and France. The Group also maintains a corporate office in The Netherlands.

The following table summarizes IPC's full-time equivalent employees as at December 31, 2024:

Country	Employees
Canada	160
Malaysia	62
France	47
Switzerland	28
Total	**297**

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 in areas where the Group does not require full time employees.

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 the potential acquisition of new oil and gas assets and for skilled technical personnel with a substantial number of other oil and gas companies, many of which may have greater technical or financial resources.

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" in Canada, could affect access in certain circumstances. See also "Risk Factors".

Environmental Regulations

The Group's oil and gas operations, and the oil and natural gas industry generally, are subject to environmental regulation under applicable laws and regulations, which are subject to review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, emissions management, habitat protection and the operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation for air pollution and greenhouse gas emissions, may impose further requirements on the Group and other companies in the oil and natural gas industry. Compliance with these current and future environmental regulations might have a significant negative impact on IPC's financial position. See also "Industry Conditions" and "Risk Factors".

Climate Regulations

Climate change regulation at international, national and regional levels has the potential to significantly affect the regulatory environment of the oil and natural gas industry where the Group operates.

In general, there is some uncertainty with regard to the impacts of climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on IPC's operations and cash flow from operating activities. See also "Industry Conditions" and "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 Guidelines 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.sedarplus.ca under the Corporation's profile or on IPC's website at www.international-petroleum.com.

The Corporation's Sustainability Policy is articulated around the Corporation's six sustainability priorities: health and safety, rewarding workplace, communities, climate action, environmental stewardship, and ethics and integrity. The framework aligns with the United Nations Sustainable Development Goals and IPC's UN Global Compact commitments.

In 2024, IPC presented its fifth Sustainability Report detailing the Corporation's environmental, social and governance (ESG) performance and confirmed its target to reduce net greenhouse gas (GHG) emissions intensity to the global average by the end of 2025, which would represent a 50% reduction relative to the Corporation's 2019 baseline. In February 2024, IPC extended this commitment to the end of 2028. IPC's Sustainability Report may be accessed on IPC's website at www.international-petroleum.com. See also "Industry Conditions" and "Risk Factors".

In 2020, IPC joined the United Nations Global Compact, a leading global initiative for good corporate citizenship. IPC supports and is committed to upholding the 10 Principles of the UN Global Compact on human rights, labour, environment and anti-corruption, and reports on progress on an annual basis.

INDUSTRY CONDITIONS

Industry Overviews and Regulatory Regimes in Canada, Malaysia and France

Canada Country Overview

Companies carrying on business in the oil and natural gas industry in Canada are subject to extensive controls and regulations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. IPC holds interests in oil and natural gas properties, along with related assets, in the provinces of Alberta and Saskatchewan, Canada. Regulated aspects of IPC's business include activities associated with the exploration for and production of oil and natural gas, including: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations of and access to operational sites; (iv) operating standards; (v) environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites.

The discussion below outlines certain conditions and regulations that impact the oil and natural gas industry generally in Canada.

Pricing and Marketing in Canada

Oil

Producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance, tariffs and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/

demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms. Natural gas prices in Canada reached record lows in 2024 due to increasing North American supply, limited access to markets and limited storage capacity. There are currently eight liquefied natural gas (LNG) export projects at different stages of development across the country with most being located in British Columbia. Most of the other projects target becoming operational between 2027 and 2030, although there is no guarantee that all or any of these projects will proceed.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in western Canada have experienced low pricing relative to other markets in the past. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for oil and natural gas, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian oil and natural gas industry. Several proposals have been in the past been proposed to increase pipeline capacity out of western Canada, to reach eastern Canada, the United States and international markets, including via export shipping terminals on the west coast of Canada. While certain projects have proceeded, such as the TransMountain Pipeline expansion, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

The TransMountain Pipeline expansion commenced commerical operations in the first half of 2024. With the expansion completed, the system's capacity increased from approximately 300,000 to 890,000 barrels per day.

Land Tenure

Crown

Rights are granted to energy companies to explore for and produce oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Lease terms vary in length and incorporate terms and conditions as set forth in legislation, including continuation requirements, obligations to perform specific work, or make payments.

Lands in oil and natural gas leases are continued beyond their primary term by drilling a well(s) where certain minimum thresholds of production have been reached, all lease rental payments have been made on time and certain other conditions have been met. A lease is proven productive at the end of its primary term by drilling, producing, mapping (Alberta), being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease until the lease holder can no longer prove the lands are capable of producing oil or gas.

Oil sands leases are continued beyond their primary term by meeting a minimum level of production (MLP), or by paying an escalating rental in lieu of achieving the MLP.

Many jurisdictions in Canada, including the provinces of Alberta and Saskatchewan, have legislation in place for mineral rights reversion to the Crown where stratigraphic formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to continue lease terms for non-producing lands, having met certain criteria as laid out in the relevant legislation.

Freehold

In addition to Crown ownership, oil and natural gas can also be privately owned (freehold). Rights to explore for and produce such oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the mineral holder and oil and natural gas producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Royalties and Incentives

Each province in Canada has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. Provincial royalty regimes operate in conjunction with applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

From time to time, the Canadian federal government and provincial governments create incentive programs for businesses operating in specific industries, including those in the oil and gas industry. These are often introduced when commodity prices are low to encourage exploration and development activity, and may provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or to utilize technologies that enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

Regulatory Authorities and Environmental Regulation

General

The oil and natural gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, emissions management, habitat protection and the operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry, including a proposed cap on GHG emissions from all oil and gas operators. This is likely to impose further requirements and costs on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

Alberta

The Alberta Energy Regulator ("**AER**") is the single regulator responsible for all resource development in Alberta. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

Saskatchewan

Environmental compliance in Saskatchewan is governed by The Oil and Gas Conservation Act (Saskatchewan), including The Oil and Gas Conservation Regulations, 2012 (Saskatchewan) (the "**OGC Regulations**") and The Petroleum Registry and Electronic Documents Regulations. Environmental compliance in Saskatchewan is also subject to the Environmental Management and Protection Act, 2010 and the Environmental Management and Protection (Saskatchewan Environmental Code Adoption) Regulations. The environmental laws take a results-based approach which incorporates the required outcomes into regulations, and leaves the specific methods on how to achieve that outcome up to the resource company. The Government of Saskatchewan also established a set of oil and gas operating directives and environmental standards, including environmental site assessment guidelines, acknowledgement of reclamation requirements and incident reporting requirements.

Liability Management

In 2020, the Government of Alberta announced a new liability management program that overhauls and modernizes the previous liability management program, known as the Liability Management Ratio ("**LMR**") which uses a licensee's ratio of deemed asset value to deemed liability value to determine the risk that the licensee poses to the Orphan Well Association and to determine if a security deposit is required to mitigate that risk. The LMR was replaced by Directive 088: Licensee Life-Cycle Management ("**LLCM**"), which directive was released and became effective on December 1, 2021. Unlike the LMR, which measures two metrics to determine a licensee's risk, the LLCM assesses more than 30 additional metrics, such as the licensee's financial capability, previous closure activity, operational performance and regulatory compliance. Additionally, the new liability framework includes an Inactive Inventory Reduction Program which introduced annual mandatory liability reduction spending targets for each licensee. The new framework also includes the development of a program to address legacy sites that were abandoned, remediated or reclaimed before current requirements were introduced. In September 2022, the AER introduced the Closure Nomination Program as part of LLCM. This program allows for specific, direct stakeholders to nominate inactive sites for abandonment and/or reclamation.

The Government of Saskatchewan also announced enhancements to its Liability Management Program framework in 2020. This framework includes using licensee-specific data to better reflect the actual deemed asset and liability values, which is expected to improve the accuracy of License Liability Ratings; an Inactive Liability Reduction Program that requires an annual spending target on closure activities; completing the Proportional Risk Transfer model that will assess security deposit requirements for license transfers with a high amount of inactive infrastructure; and addressing regulatory gaps related to new entrants and the acceptable forms of security deposits. To support these new initiatives, the Government of Saskatchewan has enacted The Financial Security and Site Closure Regulation, which came into force on January 1, 2023.

Climate Change Regulation

Climate change regulation at international, federal and provincial levels has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on IPC's operations and cash flow from operating activities.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40 to 45% below 2005 levels by 2030, and to net-zero by 2050. During the 2021 United Nations Climate Change Conference, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In June 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO_2e emissions. The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country.

Originally under the federal plans, the price was set to escalate by CA$10 per year until it reached a maximum price of CA$50 per tonne of CO_2e in 2022. However, in December 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO_2e increases by CA$15 per year until it reaches CA$170 per tonne of CO_2e in 2030 (as of January 1, 2025: CA$95 per tonne). While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released in March 2021. There remains uncertainty whether the federal government will in the future amend or replace these regulations.

In 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector and came into force on January 1, 2020. By introducing new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent.

In December 2023, the federal government stated that the existing measures, which were designed to reduce the oil and gas sector's methane emissions by 40 to 45% by 2025 (relative to 2012) would not be sufficient to meet Canada's commitment to achieving a 75% reduction (below 2012 levels) by 2030. Accordingly, it released proposed amendments which would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems. The proposed amendments are targeted to come into force in January 2027.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

The Canadian Net-Zero Emissions Accountability Act (the "**CNEAA**") came into force in June 2021. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and

Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") in March 2022. In the 2030 ERP, the Government of Canada proposes a roadmap to reduce its GHG emissions by 40 to 45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

In June 2022, the Canadian Greenhouse Gas Offset Credit System Regulations were published. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets. Currently, there are no approved federal offset protocols applicable to the oil and gas sector.

In July 2023, the federal Clean Fuel Regulations took effect. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives, imposing obligations on primary suppliers of transportation fuels in Canada, and requiring fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

In November 2024, the federal government published the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (the "**Proposed Regulations**"). The Proposed Regulations would cap emissions from a range of oil and gas related activities, create an emissions cap-and-trade system, and require facility operators to comply with various reporting and remittance obligations. The final version of the Proposed Regulations is expected to be published in mid-2025 and come into force by January 1, 2026. There remains uncertainty whether the federal government will in the future amend or replace these regulations.

The Government of Canada has developed a Carbon Management Strategy, whereby it aims to deploy various carbon management technologies, including carbon capture, to help achieve federal climate goals. Carbon Capture is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing CA$319 million over seven years into research, development and demonstrations to advance the commercial viability of carbon capture technologies.

In June 2024, the federal government enacted various new tax credits for sustainability-related projects, including the Carbon Capture, Utilization, and Storage ("**CCUS**") Investment Tax Credit ("**ITC**"). The CCUS ITC is a refundable tax credit that applies to certain expenses incurred for eligible CCUS projects. It was enacted on June 19, 2024 (but deemed to have come into effect on January 1, 2022). The credit is available from January 1, 2022 until December 31, 2040, with the magnitude of the credit being reduced by 50% beginning on January 1, 2031.

In June 2023, the IFRS issued two international reporting standards on sustainability: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The Canadian Sustainability Standards Board ("**CSSB**") subsequently released for public comment substantially similar proposed Canadian versions of the international standards ("**CSDS 1**" and "**CSDS 2**"), which were finalized in December 2024 (collectively, the "**Canadian Standards**").

The Canadian Standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 emissions (i.e. indirect emissions from an organization's operations). The finalized Canadian Standards are substantially similar to IFRS S1 and S2 (and earlier drafts of CSDS 1 and CSDS 2), however they have extended implementation timelines for select criteria. Canadian companies are not required to follow the Canadian Standards at this time, however the Canadian Securities Administrators are considering amending Canadian reporting requirements to include certain aspects of these new Canadian Standards; to what extent they will be adopted remains unclear.

In June 2024, the federal Competition Act was amended to enact new deceptive marketing provisions targeting "greenwashing". The new provisions introduced unclear substantiation requirements for companies making environmental claims and significant fines for failing to meet the new requirements. As a result of the uncertainty with respect to the applicability of the new rules, some companies removed their environmental and sustainability-related disclosure from the public domain.

Alberta and Saskatchewan

In December 2016, the Oil Sands Emissions Limit Act (Alberta) came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. Alberta's oil sands emitted roughly 82 megatonnes of GHG emissions in 2023, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. In December 2019, the federal government approved Saskatchewan's Management and Reduction of Greenhouse Gases Regulation ("**MRGHGR**") and Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The MRGHGR came into effect on January 1, 2019 (as amended on January 1, 2023). The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The MRGHGR and TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, and the federal backstop continues to apply to emissions sources not covered by the regulation.

The GGPPA system applies in part in Saskatchewan for specific industry sectors, and the federal backstop continues to apply to emissions sources not covered by the provincial emissions legislation.

The Government of Alberta committed to lowering annual methane emissions from 2014 levels by 45% by 2025 and reached this target 3 years early. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

In 2024, the Government of Saskatchewan and Canada entered into a similar equivalency agreement such that the Federal Methane Regulations will not apply in Saskatchewan.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("**UNDRIP Act**") came into force in Canada. The UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

As of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP (the "**Implementation Secretariat"**), consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles. In June 2023, the Implementation Secretariat released The United Nations Declaration on the Rights of Indigenous Peoples Act Action Plan (the "**Action Plan**") with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe. In June 2024, the federal government tabled its Third Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"), which provides various progress updates, including on the implementation of Canada's Action Plan.

Various Indigenous-related legislation is currently being considered, and related regulations being developed, by the federal government, including the proposed First Nations Clean Water Act and regulations regarding Indigenous impact assessment co-administration agreements. In addition to the changing legislative landscape, common law precedent regarding existing and new Indigenous-related laws continues to develop. Such developments are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

Accountability and Transparency

In 2015, the federal government's Extractive Sector Transparency Measures Act (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to the ESTMA must report payments over CAD 100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments. IPC's ESTMA report for the year ended December 31, 2024 will be available on the Corporation's website at www.international-petroleum.com.

Corporate Sustainability Reporting Directive

The Corporate Sustainability Reporting Directive ("**CSRD**") originally entered into force in 2023 introducing proposed new requirements for companies in the EU to include disclosures related to climate, the environment and wider sustainability issues. Substantial amendments to the CSRD requirements were proposed by the EU in February 2025. The Corporation continues to review the applicability and scope of the CSRD.

Malaysia Country Overview

Industry Summary

Malaysia's upstream sector has been built upon the oil and gas fields in the shallow waters off Peninsular Malaysia and Sarawak. Oil production in Malaysia began in the early part of the 20th century. In the 1960s, exploration activity moved offshore and the first significant fields were brought onstream. Malaysia is now considered a relatively mature oil producer.

Gas is an increasingly important component of the energy economy of Malaysia, as evidenced by the comparison of liquids and gas production through time. Gas production in Malaysia can be split into peninsular production, supplied for domestic consumption in peninsular Malaysia, and Borneo production, the majority of which is converted to liquefied natural gas for export at the Bintulu plant in Sarawak.

All of IPC's oil and gas assets in Malaysia are located offshore Peninsular Malaysia.

Regulatory Framework

Key Legislation

Petroleum Development Act

The Petroleum Development Act 1974 (the "**PDA**") and the Petroleum Regulation 1974 enacted pursuant to the PDA (the "**Petroleum Regulation**") are the key legislative enactments that govern oil and gas exploration activities both onshore and offshore in Malaysia. The PDA came into force on October 1, 1974. Pursuant to the PDA, the entire ownership in, and the exclusive rights, powers, liberties, privileges of exploring, winning and obtaining petroleum onshore and offshore were vested in Petronas, Malaysia's national oil company. The vesting of the ownership, rights, powers, liberties and privileges from Malaysia to Petronas is in perpetuity and irrevocable. The PDA and the Petroleum Regulation also set out the licensing requirements for upstream activities and the downstream activities of refining, marketing and distributing oil products.

Petroleum (Income Tax Act) 1967

The Petroleum (Income Tax) Act 1967 ("**PITA**") governs the taxation of petroleum income in Malaysia.

Environmental and Decommissioning

Decommissioning of oil and gas facilities and pipelines is governed by a number of laws due to the variety of activities that are required to undertake abandonment and decommissioning. Such laws include the Continental Shelf Act 1966, the Exclusive Economic Zone Act 1984, the Petroleum (Safety Measures) Act 1984, the Environmental Quality Act 1974, the Occupational Safety and Health Act 1994, the Fisheries Act 1985, the Merchant Shipping Ordinance 1952 and the Merchant Shipping (Oil Pollution) Act 1994. In summary, the laws require that the abandonment and decommissioning activities be carried out safely, not cause any environmental degradation and not interfere with other offshore activities such as fishing.

In 2024, Malaysia announced plans to introduce a carbon tax on the Malaysian energy industry commencing in 2026. The Group will continue to monitor this situation and, when further details are provided by the Malaysian authorities, will assess the potential effects of this proposed tax on the Group's business in Malaysia.

Other Key Legislation

The Petroleum (Safety Measures) Act 1984 (the "**PSMA**") and the regulations thereunder govern the transportation, storage and handling of oil and oil products. The Environmental Quality Act 1974 (the "**EQA**") is the main legislation governing the protection of the environment and the protection of oil spills and pollutants on land and in Malaysian waters.

Regulatory Body

As a result of the PDA, Petronas exercises regulatory powers in respect of the upstream sector. Any person wishing to engage in exploration activities is required to be authorized to do so by Petronas, either by entering into a PSC or by obtaining a licence from Petronas to provide services to the upstream industry.

Production Sharing Contracts

Since the enactment of the PDA, a person seeking to obtain rights to explore, develop and produce petroleum is required to enter into a PSC with Petronas.

Almost all licences in Malaysia are presently governed by PSCs. The terms and scope of the rights granted are entirely contained in the PSC and such rights are enforceable under Malaysian law. The terms of the PSC provide that the party to the PSC (the "**PSC Contractor**") is solely responsible for the provision of all funds required directly or indirectly for petroleum operations. The PSC Contractor is then entitled to recover costs related to petroleum operations and a share of profits from the production of crude oil or natural gas in kind, based on a defined formula contained in the PSC.

PSCs also set out specific responsibilities for decommissioning and abandonment. The terms of the PSC require that PSC Contractors make payments to a fund for abandonment and decommissioning operations known as the "abandonment cess". Payment of the abandonment cess commences upon commercial production of petroleum and is payable on an annual basis. Such payments are cost recoverable under the terms of the PSC.

Fiscal Terms

Petroleum (Income Tax Act) 1967

Petroleum income tax is charged on the income of every "chargeable person" derived from "petroleum operations" in Malaysia at a rate of 38%. The "chargeable persons" under PITA are Petronas, the Malaysia-Thailand Joint Authority and PSC Contractors in respect of each PSC. PSC Contractors are taxed on a per-PSC basis on the profit oil and profit gas, less allowable deductions and capital allowances, produced from its operations in Malaysia. PITA allows qualifying exploration expenditures and expenditures wholly and exclusively incurred in the production of gross income to be deducted from gross income.

Tax Incentives

To encourage the development of marginal Malaysian fields, enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature, and deep water projects, the government introduced new tax incentives through the following subsidiary legislation:

- Petroleum (Income Tax) (Exemption) Order 2013 (the "**Exemption Order**");
- Petroleum (Income Tax) (Accelerated Capital Allowances) (Marginal Field) Rules 2013 (the "**ACA Rules**");
- Petroleum (Income Tax) (Marginal Field) Regulations 2013; and
- Petroleum (Income Tax) (Investment Allowance) Regulations (the "**IA Regulations**", and collectively, the "**New Tax Incentives**").

The New Tax Incentives took effect in November 2010. The ACA Rules allow for accelerated capital allowance on qualifying plant expenditures incurred for petroleum operations in a marginal field. Applying the accelerated capital allowance rate, capital allowance on qualifying plant expenditures can be fully claimed within five years as opposed to ten years based on conventional capital allowance rates. Under the Exemption Order, the Minister exempts a portion of the statutory income derived from petroleum operations in a marginal field, which results in "chargeable income" derived from marginal fields being taxed at 24.966% instead of 38%.

The IA Regulations provide for an investment allowance equal to 60% of qualifying capital expenditures incurred in a period for a year of assessment within a period of ten years in respect of a qualifying project; or on an infrastructure asset as determined by the Minister. A "qualifying project" is a project that carries out either enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature, or any combination thereof; or a project in an area under a PSC in respect of a deep water project. This results in a 60% investment allowance in addition to capital allowance, and 70% of statutory income from a qualifying project is tax exempted equal to the investment allowance available.

Royalties

The PDA expressly stipulates that in return for the vesting of ownership and rights in the petroleum resources, Petronas is to make cash payments to the federal government and the government of the state in which petroleum is produced. The payments are made by Petronas in the form of royalty payments to the federal government, which are in turn distributed to the applicable state governments. The source of these payments is the production of oil and gas under various PSCs. Under the PSC framework, 10% of all petroleum won and saved by PSC Contractors is paid to Petronas in order to satisfy payment of royalties under the PDA.

Profit Sharing

Apart from the royalty payments, PSC Contractors are also required to share a certain proportion of profit oil or profit gas from crude oil and natural gas produced with Petronas, based on a predetermined formula. In order to share in any upside in the price of oil, PSC Contractors are required to make supplemental cash payments to Petronas for such portion of the PSC Contractor's portion of the profit oil or profit gas that exceeds the specified base price agreed in the PSC.

France Country Overview

Industry Summary

France is a mature hydrocarbon country. French production originates from three main sedimentary basins known as the Aquitaine, Paris and Alsace basins. All of IPC's material oil and gas assets in France are located in the Paris Basin and the Aquitaine Basin.

Regulatory Regime Summary

There are essentially two types of licence: exploration and production. All licensing regulations are controlled by the General Department of Energy and Climate in conjunction with the General Council of Mines.

The fiscal terms which apply to the upstream oil and gas industry in France are based on a concession system. Business tax and royalties are payable to the government and further local levies are payable to the local authorities where the fields are situated. For 2024, the corporate tax rate was 25% with a social surtax of 3.3% on the amount of tax paid in excess of EUR 763,000, resulting in a marginal tax rate of up to 25.825%.

French law prohibits the use of certain techniques, including hydraulic fracturing, which effectively prohibits exploration for and development of unconventional oil and gas deposits in France.

Regulatory Framework

Key Legislation

In France, all mining resources from the subsoil, including oil and gas, belong to the state. The Mining Code allows the government to delegate to companies the right to explore the subsoil and produce oil and gas. The Mining Code defines the process by which exploration permits (permis exclusifs de recherches) and production licences (concessions) may be granted and how royalties should be set. In addition, the General Code of Taxation (Code general des impots) details how Communal and Departmental taxes, as well as corporate income tax payable to the state, are calculated. From a law 2017-1839 dated December 30, 2017 (the "**Hydrocarbon law**"), new exploration permits (permis exclusifs de recherches) can no longer be granted and production licenses (concessions) can be granted and renewed only under certain conditions.

Regulatory Body

The Minister for the Ecological Transition (acting as the Ministry of the Environment), together with the Minister for the Economy and Finance, who are jointly in charge of mining, are responsible for granting the licenses. License applications are processed by the General Department of Energy and Climate (Direction Générale de l'Energie et du Climat) and, more specifically, the Energy Department (Bureau des ressources énergétiques du sous-sol) of the Ministry for the Ecological Transition. Regulation and administration of the mining activities are carried out through the local state representatives.

Exploration Permits (permis exclusif de recherches)

From the Hydrocarbon law, new exploration permits (permis exclusifs de recherches) can no longer be granted in France. Exploration permits granted prior to December 30, 2017 were awarded for an initial period of five years or less, with a financial commitment referring to an agreed work programme. These permits have not been affected by the Hydrocarbon law and may be renewed twice, each time for five years or less. Applications for extension of exploration permits granted prior to December 30, 2017 are submitted to the Minister in charge of mining. If the work programme requirements for the current period have been completed, renewals are not generally rejected. The extension of exploration permits is granted by an order (arrêté) of the Minister in charge of mining.

Any transfer to a new permit holder must be submitted to the Minister in charge of mining for approval. Any project for a change of control of the exploration permit holder must be prior notified to the Minister in charge of mining, who has a two-month period, that may be renewed once, to oppose the project.

Production Licences (Concessions)

The concession is granted for a period of not more than 50 years and could be renewed several times for 25 years or less. From the Hydrocarbon law, no new production license can be granted, except when the production license is to cover a discovery made under an exploration permit granted prior to December 30, 2017. The initial period of the concession is flexible and is generally shorter for smaller developments. It should be noted that production can commence from a new field on an exploration permit prior to the award of a concession.

The award of concessions is subject to a specific procedure and to certain conditions. In the case where the applicant has already been granted an exploration permit on the corresponding area prior to December 30, 2017, a production license can be awarded for a period that cannot extend beyond January 1, 2040, except if it can be demonstrated that the costs incurred have not been recovered by this date. The procedure of granting involves in particular a public enquiry (enquête publique). The concession is granted by decree (décret en Conseil d'Etat).

Production licenses granted prior to December 30, 2017 can be renewed for 25 years or less but, as per the Hydrocarbon law, they cannot be renewed for a duration extending beyond January 1, 2040.

French Decree 2006-648 dated June 2, 2006 relating to mining licences provides, in particular, the following:

- any project which may involve a change of control of the licence-holding company (whether direct or indirect) needs to be notified to the Minister of Mines in advance. The Minister of Mines has a two-month period (which can be extended to four months) to oppose the project; and
- any project which involves a material modification to the financial and technical capabilities taken into consideration at the time when the licence was granted must be notified to the Minister of Mines.

With the Hydrocarbon law, the French government has decided to stop granting future petroleum exploration permits in France and to cease the production of oil and gas under existing production licenses in France from 2040.

Fiscal Terms

Mineral rights in France belong to the French State, and production of hydrocarbons occurs under a concession regime. Holders of a concession or production license must pay the French tax authorities a royalty proportional to the value of the products extracted. This royalty is paid starting from production. Under the current French Mining Code, the royalty payable for a concession is 8% of the portion of the annual production above 1,500 tonnes per year extracted from that concession.

Local mining taxes, or RCDM (redevance communale et départementale des mines), are also payable to the applicable administrative French country and municipality on whose territory the oil is produced. Each local tax is determined by multiplying production by a unit rate, which is set each year by the Ministry for the Ecological Transition. The local mining tax is payable in arrears (production of 2023 is reported in 2024 and the corresponding tax is paid, after receipt of the notice of payment, generally end 2024 or beginning 2025), is ring-fenced by well. For 2024, the RCDM was set at EUR 34.586 per net tonne of oil equivalent.

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 IPC's common shares ("Common Shares") to decline. If any of the following risks actually occur, the Group's business may be adversely affected, and the Group's financial condition and results of operations may suffer significantly.

Exploration, Development and Production Risks: Oil and 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 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 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. While diligent well supervision, effective maintenance operations and the development of EOR technologies can contribute to maximizing production rates over time, it is not possible to eliminate 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.

IPC uses multi-well pad drilling in certain situations where practicable. Wells drilled on a pad may not be placed on production until all wells on the pad are drilled and completed. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in operating results.

Oil and 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, hydrocarbon releases and spills, each of which could result in substantial damage to oil and 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 and Price Differentials and Tariffs: The demand for energy, including oil and gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political developments in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine and elsewhere and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy.

The marketability and price of oil and 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 gas may depend upon its ability to access space on pipelines that deliver oil and 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, the capacity of such pipelines and 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 gas and many other aspects of the oil and 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 and OPEC+, strategic petroleum reserve management and imposition of tariffs by the United States, the conflict in Ukraine, the impact of pandemics, 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 and the availability of alternative fuel sources.

In March 2025, the United States proposed a 25% broad-based tariff on goods exported out of Canada into the United States, other than energy products (including oil and natural gas), which are subject to a 10% tariff. In response, the Canadian government announced that it would impose potential tariffs on goods imported from the U.S. The U.S. also announced potential tariffs on goods imported from Mexico and a tariff on goods imported from China. Subsequently, the United States delayed tariffs on goods from both Canada and Mexico that are covered by the United States-Mexico-Canada Agreement until April 2025. Representatives of the U.S. government have also publicly stated that they are considering imposing tariffs on goods imported from other countries. These tariffs, and any changes to these tariffs or imposition of any new tariffs, taxes or import or export restrictions or prohibitions, could have a material adverse effect on the Canadian oil and natural gas industry and the Corporation. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war which could have a material adverse effect on the global economy, and by extension the Canadian oil and natural gas industry and the Corporation. It is uncertain how long the current tariffs will remain in place and what the impact will be on the prices of Canadian oil and gas and on the financial condition of the Corporation. The introduction of new trade policies or barriers, including the imposition of new tariffs, duties or other trade restrictions on Canadian hydrocarbon products exported to the U.S., or the imposition of new or retaliatory tariffs, duties or trade restrictions on hydrocarbon products imported into Canada from the U.S., could result in a decrease in, or increase the volatility of, commodity prices and/or price differentials which could, in turn, reduce the demand for oil and natural gas and have an adverse effect on the Corporation's business, financial condition and results of operations.

Oil and 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 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.

The Group's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials in Canada between the Group's heavy crude oil (in particular the heavy crude oil differential) and quoted market prices. The market price for heavy crude oil and bitumen in Canada is generally lower than market prices for light oil, due principally to the higher costs associated with refining a barrel of heavy crude oil and higher transportation costs (diluent is required to be purchased and blended with heavy crude oil to transport on most pipelines). Heavy crude oil differentials are also influenced by other factors such as capacity and interruptions, refining demand and the quality of the oil produced, all of which are beyond the Group's control. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on the Group's business, financial condition, results of operations and cash flows.

In addition, there has not been, at times, sufficient pipeline capacity to export all Canadian crude oil and the availability of alternative transport capacity is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term export capacity or that currently operating systems will remain in service. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption, refinery outages and/or increased supply of crude oil, will not occur.

In order to transport crude oil production in Canada to sales markets, the Group is required to meet certain pipeline specifications. Heavy crude oil and bitumen is usually blended with diluent to increase its flow characteristics. The cost of diluent is generally correlated to crude oil prices. A shortfall in the supply of diluent may cause its price to increase which would adversely affect the Group's financial position and cash flow.

Climate Change: Climate change issues are an important factor for the oil and gas industry.

Transition Risks

The Group's facilities and operations, and the oil and gas that the Group markets, result in the emission of greenhouse gas ("GHG") which makes the Group subject to GHG emissions legislation and regulation. Governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions commonly and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Group's operating expenses, and, in the long-term, potentially reducing the value of oil and gas assets.

Regulatory climate change related risks arise from increased or amended environmental regulation. A breach of such regulations 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, or limitations on, GHG emissions or emissions intensity. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges 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 GHGs could have a material impact on the operations and financial condition of the Corporation. Increased scrutiny of applications for oil and gas licenses, permits and authorizations to develop assets and projects could lead to delay, limit or prevent future development of assets or affect the productivity of assets and the costs associated.

In addition, concerns about climate change and public discussion that oil and gas operations may be associated with 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 GHGs and resulting requirements, it is not possible to predict the impact on the Group and its operations and financial condition.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. Individuals, governmental authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While IPC is not a party to any such litigation or proceedings, IPC could be named in actions making similar allegations. An unfavourable ruling in any such case could adversely affect the demand for and price of the Common Shares, impact the Group's operations and have an adverse impact on IPC's financial condition.

Emission and carbon tax regulations in Canada federally and regionally are evolving and as these regulations are established or amended, they may have an impact on companies involved in oil production in Canada. The federal Government of Canada has taken steps to address climate change by establishing the Canadian Net-Zero Emissions Accountability Act that brings into law the commitment to achieve net-zero GHG emissions by 2050 and issuing the 2030 Emissions Reduction Plan that describes the measures Canada is undertaking to reduce emissions to 40 to 45 percent below 2005 levels by 2030. In November 2024, the Government of Canada commenced a consultation process with respect to draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, under which specific limits on emissions from the oil and gas sector would be imposed with the intention to reduce the carbon intensity of oil and gas production in Canada, with a focus on improving energy efficiency, fostering the adoption of cleaner technologies, and accelerating the transition to more sustainable practices. It is difficult to assess the overall impact all of these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business. There remains uncertainty whether the Canadian federal government will in the future amend or replace these regulations.

The International Sustainability Standards Board ("**ISSB**") was created on November 3, 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. On June 26, 2023, the ISSB issued IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information" and IFRS S2 "Climate-related Disclosures". The Corporation is actively evaluating the potential effects of the ISSB issued sustainability standards; however, at this time, the Corporation is not able to determine the impact on future financial statements, nor the potential costs to comply with these sustainability standards.

In December 2024, the Canadian Sustainability Standards Board released its voluntary and non-binding Canadian Sustainability Disclosure Standards: CSDS 1 – General Requirements for Disclosure of Sustainability-related Financial Information and CSDS 2 – Climate-related Disclosures, which are effective for annual reporting periods beginning on or after January 1, 2025. CSDS 1 and CSDS 2 establish a set of sustainability and climate-related disclosure standards for Canadian companies that are modelled on those developed by the ISSB. While these Canadian standards are non-binding, they could influence the development by securities regulators of sustainability and climate-related reporting obligations for Canadian public companies under applicable Canadian law.

The Corporate Sustainability Reporting Directive ("**CSRD**") entered into force in 2023 introducing requirements for certain companies in the EU, to include disclosures related to climate, the environment and wider sustainability issues. Substantial amendments to the CSRD requirements were proposed by the EU in February 2025. The Corporation continues to review the applicability and scope of the CSRD.

In 2024, Malaysia announced plans to introduce a carbon tax on the Malaysian energy industry commencing in 2026. The Group will continue to monitor this situation and, when further details are provided by the Malaysian authorities, will assess the potential effects of this proposed tax on the Group's business in Malaysia.

If the Group is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, IPC's business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected.

Physical Risks

Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, wildfires, droughts or floods, or long-term shifts in climate patterns with sustained higher temperatures, water stress or sea level rise. These physical risks may have financial and operational implications for the Group, such as direct damage to assets and indirect impacts from supply chain disruption to the delivery of goods and services. Certain of IPC's oil and gas assets are in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage.

Sustainability Targets and Disclosures: IPC is targeting to reduce its net GHG emissions intensity. IPC's ability to achieve these targets is subject to numerous risks and uncertainties, and actions taken in implementing these objectives may also expose the Group to certain additional and/or heightened financial and operational risks. In addition, the cost associated with achieving emissions reductions targets and other climate and sustainability targets could be significant, and could require significant capital expenditures and resources, potentially including the acquisition of technology, with the potential that the costs required to achieve targets could differ from original estimates and expectations, which differences may be material. Failure to achieve emissions, climate or sustainability targets could have a negative impact on IPC's reputation, business, cash flows, results of operations, and on the Group's access to, and cost of, capital.

In June 2024, the Canadian federal government amended the Competition Act (Canada) with respect to how companies communicate about environmental goals and performance and to address "greenwashing", meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. There is uncertainty regarding how this new legislation will be interpreted and applied. Statements made in this AIF in respect of activities undertaken or to be undertaken by IPC with respect to protecting or restoring the environment or mitigating environmental and ecological causes or effects of climate change, including the provision of emissions figures and forecasts, the acquisition and use of carbon offsets, activities to potentially reduce emissions, and activities to provide for environmental stewardship, including water management and biodiversity, should not be relied upon for the purposes of investing in securities of IPC or otherwise be considered as promoting IPC's products or business interests. In June 2025, new private rights of action will come into effect, meaning that any person will be able to bring a complaint directly to the Competition Tribunal for an alleged violation of the new greenwashing provisions. The Competition Bureau has published draft guidance regarding how it will apply the new greenwashing provisions, however the guidance, even once finalized, is not and will not be binding on private parties nor the Competition Tribunal. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of CA$10 million for the first order and CA$15 million for any subsequent order, and 3% of the company's annual worldwide gross revenues.

Reputational Risks: Reputational risks arise from societal pressure on the fossil fuel industry in relation to its contribution to global GHG emissions. Maintaining a positive reputation in the eyes of investors, regulators, communities, employees and the general public is an important aspect for the success of the Corporation. Negative impact on the industry and the Corporation's reputation could result in the long-term delays in obtaining regulatory approvals, increased operating costs, lower shareholder confidence, or availability of insurance and financing.

Oil and gas operations may be subject to public opposition. Such public opposition could result in higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental groups and other organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation.

Project Risks: The Group is undertaking various projects, including Phase 1 of the Blackrod project. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. IPC's ability to execute projects depends upon numerous factors beyond its control, including: processing, pipeline and storage capacity, availability of water, electricity, gas, diluent and other operational supplies, effects of weather, availability of personnel and equipment, unexpected cost increases, accidents, regulatory and third party approvals and commercial arrangements, stakeholder consultations (including Indigenous consultation) and regulatory changes (including carbon tax). As a result of these and other factors, the Group may be unable to execute projects on time, on budget, or at all.

Inflationary Pressures and Costs: The Group's operating costs could escalate and make operations unprofitable due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention. Labour costs, abandonment, reclamation, gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. The inability to manage costs may impact project returns and future development decisions, which could have an adverse effect on financial performance. The cost or availability of oil and gas field equipment may adversely affect IPC's ability to undertake projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to operations or projects for the expected price, on the expected timeline, or at all, may have an adverse effect on financial performance.

The Group's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality construction standards and supply chain disruptions. Fluctuations in operating and capital costs could negatively impact the Group's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Group's assets, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions 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; 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, 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.

Reductions in Demand for Oil and Gas: Increasing consumer demand for alternatives to oil and gas, conservation measures, alternative fuel requirements, and technological advances in fuel economy and renewable energy generation systems, could reduce the demand for oil and gas. Some jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and to encourage the use of renewable fuel alternatives, which could reduce the demand for oil and gas. Advancements in energy efficient products have a similar effect on the demand for oil and gas. The Corporation cannot predict the impact of changing demand for oil and gas products, and any major changes may have an adverse effect on IPC's business, financial condition, results of operations and cash flow from operations by increasing costs, limiting access to capital and decreasing the value of oil and gas assets.

Uncertainties Associated with Estimating Reserves and Resources Volumes: There are numerous uncertainties inherent in estimating quantities of oil and gas reserves and resources (contingent and prospective) and the future cash flows attributed to such reserves and resources. The cash flow information associated with reserves and resources set forth in this AIF 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 Corporation and the Corporation'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 gas, curtailments or increases in consumption by oil and 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". This AIF contains estimates of the net present value of the future net revenue from IPC's reserves and resources. 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 reserves and resource evaluations will be attained and variances could be material. See also "Reserves and Resources Advisory" below.

SAGD Recovery Process: The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and the Blackrod project. The SAGD recovery process requires a significant amount of gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule. In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

Hydraulic Fracturing: Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil and gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims, and could increase costs of compliance, as well as delay development of certain oil and gas resources. Restrictions or bans on hydraulic fracturing could result in restricting the economic recovery of oil and gas reserves. In addition, the Group may need to dispose of the fluids produced from oil and gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Water: Water is an essential component of IPC's drilling and hydraulic fracturing processes. Limitations or restrictions on IPC's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact IPC's operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. In April 2024, in the face of severe drought risks following several warm, dry winters causing Alberta's snowpack, rivers and reservoirs to be low, Alberta entered into water-sharing agreements with 38 of the largest and oldest water licensees in southern Alberta. If the Group is unable to obtain water to use in IPC's operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on IPC's financial condition, results of operations, and funds flow.

Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment: Oil and 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 (including carbon taxes), GHG emission restrictions, royalties and the export of oil and gas. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for oil and 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.

The French government has enacted legislation to cease granting new petroleum exploration licences in France and to restrict the production of oil and gas under existing production licences in France from 2040. There is a risk that France could implement further legislative changes and that the licence regime in France could become more onerous. In Canada, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licences, permits, wells and facilities between parties. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

IPC may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact IPC's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licences and permits for activities or restrict the operation of third-party infrastructure on which the Group relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact results. Other government and political factors that could adversely affect financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards and mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for oil and gas. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for oil and gas. A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic resulting in a rise in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects such as pipelines. Protests, blockades, demonstrations and vandalism have the potential to delay and disrupt the Group's activities.

Indigenous Land and Rights Claims: In Canada, Indigenous groups have filed claims in respect of their Indigenous and treaty rights against the federal and certain provincial governments as well as private individuals and companies. Consultation delays, claims or objections related to Indigenous rights may disrupt or delay third-party operations, new development or new project approvals on the Group's properties. The Group is not aware of any claims made with respect to its properties or assets; however; if a claim arose and was successful, it may have a material adverse effect on the Group's business, financial condition, results of operation and prospects. The Group's interests at Onion Lake are situated on traditional reserve lands and are subject to the federal rules and regulations of Indian Oil and Gas Canada as well as of the Onion Lake Cree Nation of Saskatchewan/Alberta. There are risks associated with the management of the Group's interests on these lands, including access and lease terms.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfilment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Group's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals, or to advance project development, including Phase 1 of the Blackrod project.

In addition, the Canadian federal government has introduced legislation to implement the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions have introduced or passed similar legislation and have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain. Additional processes may be created and legislation associated with project development and operations may be amended or introduced, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Change of Control under Licences: The licence areas associated with the Group's oil and gas assets require government consent or compliance with regulations imposed by oil and gas regulatory authorities to effect a change of control of the owner or an assignment of the ownership interest in the licence area. There may also be contractual restrictions on assignment and change of control, including in the Suffield area of Canada where certain operations are conducted within a Canadian Forces Base under access agreements with Canadian federal government and the Alberta provincial government. Accordingly, should the Group propose to dispose of assets or if there is a change of control of the Corporation, consent may be required in order to remain in compliance with the applicable licences and concessions. The failure to obtain such consent may have a material adverse effect on the Corporation. Further, the requirement to obtain such consent may limit the ability of a third party to effect a change of control transaction with the Corporation.

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. 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 Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, most of which it does not own. The amount of oil and 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 ceased refining and 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 or increased operating or transportation costs. 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 Facilities and Bonds: The Group is, and may in the future become, party to credit facilities with international financial institutions. The Corporation has also issued bonds and may issue further bonds in the future. The terms of these facilities and bonds may contain operating and financial covenants and restrictions on the ability of the Group to, among other things, incur or lend additional debt, pay dividends, make distributions (including the repurchase of Common Shares), 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 and bonds 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.

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities may be subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the credit facilities, the Group may not have the ability to borrow funds under such facilities or may be required to repay all or a portion of the amounts owing thereunder.

If the Group fails to comply with the covenants in these facilities and bonds, is unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of the Group's assets by the creditors. The proceeds from any sale of the Group's assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards the Group's debt would the remainder, if any, be available for the benefit of shareholders.

Credit Ratings: Credit ratings affect the Corporation's ability to obtain short term and long-term financing and the cost of such financing. A reduction in the current rating or a negative change in the rating outlook could adversely affect the cost of financing and access to sources of liquidity and capital. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant. Credit ratings are not recommendations to buy, sell or hold any of the Corporation's securities.

Competition for Resources and Markets: The international oil and gas industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and gas properties and in the marketing of oil and gas. The Corporation's competitors include oil and 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 gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources and renewable energies.

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 gas production to offset the risk of revenue reduction 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 Group may not benefit from the fluctuating exchange rate if an agreement has fixed such exchange rate

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.

Certain jurisdictions in Canada, including Alberta and Saskatchewan, have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Group, which could in turn materially adversely affect IPC's business and financial condition. In addition, these liability management programs may prevent or interfere with IPC's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

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 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: Jurisdictions in which the Group operates may implement measures to facilitate management of foreign exchange risk. Such measures could restrict the Group's ability to repatriate earning or other funds.

Expiration and Renewal of Licences, Leases and Production Sharing Contracts: Certain of the Group's oil and gas assets are held in the form of licences, leases and production sharing contracts (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.

Reliance on Third Party Operators: The Group has partners in some of the licence areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, 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 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.

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.

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 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 disrupting operations and 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 Chief Operating Officer of the Corporation is principally responsible for overseeing cybersecurity risk management and for reporting such risks to other members of executive management and to the Board. 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.

Further, the Group is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, credit card and banking details (and money), or approval of wire transfer requests, by disguising themselves as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If IPC were to become a victim to a cyber phishing attack it could result in a loss or theft of financial resources or critical data and information, or could result in a loss of control of the Group's technological infrastructure or financial resources. IPC maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts regular cyber-security risk assessments. Despite efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage the Group's information technology infrastructure. The controls implemented by the Group may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on performance and earnings, as well as IPC's reputation, and any damages sustained may not be adequately covered by current insurance coverage, or at all. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Group's business, financial condition and results of operations. The protection of customer, employee, and company data is also critical to IPC's business. The regulatory environment surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. A significant breach of employee or company data could attract a substantial amount of media attention, damage relationships and reputation, and result in fines or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead to the Group being required to take additional measures to enhance security and/or assume higher liability.

The increasing prevalence of artificial intelligence (AI) tools may also increase the risk of cyber-attacks or data breaches as a result of the use of AI to launch more automated, targeted and coordinated attacks to the Corporation's technology infrastructure.

The Corporation's information technology systems may incorporate the use of AI and the development of such capabilities remains ongoing. Although the Corporation has implemented an AI Use Policy with respect to its employees' use of AI tools, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Corporation's business. AI algorithms and training methodologies may be flawed. The use of AI to support business operations of the Corporation, its partners, vendors, suppliers, contractors or others carries inherent risks related to data privacy and cyber-security, such as intended, unintended or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support. Dependence on AI to make certain business decisions without adequate safeguards may introduce additional operational vulnerabilities by producing inaccurate outcomes or other unintended results, based on flaws or deficiencies in the underlying data. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to licence, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remain uncertain and the Corporation's obligation to comply with such laws could entail significant costs, negatively affect the Corporation's business or limit the Corporation's ability to incorporate certain AI capabilities into its operations.

Insurance: Although the Group maintains insurance in accordance with industry standards to address certain risks related to oil and gas operations, such insurance has limitations on liability and may not be sufficient to cover the full extent of potential liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Group may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to IPC. The occurrence of a significant event that IPC is not fully insured against, or the insolvency of the insurer of such event, may have an adverse effect on IPC's business, financial condition, results of operations and prospects. The Group's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage.

Forced or Child Labour in Supply Chains: The Fighting Against Forced Labour and Child Labour in Supply Chains Act came into force in Canada in 2024. Pursuant to this legislation, any company that is subject to the reporting requirements, including IPC, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. Further, in late 2024 the Canadian federal government stated its intention to create a new and more onerous supply chain due diligence regime overseen by a new oversight agency whereby reporting entities will be required to scrutinize their international supply chains for human rights risks and take action to resolve any such risks. While IPC is currently unaware of any forced or child labour in any of the Group's supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which IPC has a connection, which could negatively impact IPC's reputation.

Pandemics: The Covid-19 virus and the restrictions and disruptions related to it had a material effect on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally. There can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future due to Covid-19 or other pandemics. These factors are beyond the control of the Corporation, and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's Common Shares.

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.

Key Personnel: IPC's success is in part dependent upon management, leadership capabilities and the quality and competency of key personnel. If IPC is unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have an adverse effect on the Group's financial condition, results of operations and prospects.

Change in Investors: Some institutional and other investors have announced that they no longer are willing to fund or invest in oil and gas assets or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Corporation. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Corporation, or not investing in IPC at all.

Significant Shareholder: Nemesia S.à.r.l., an investment company wholly owned by trusts whose settlor is the late Adolf H. Lundin ("Nemesia"), owns approximately 35 percent of the aggregate Common Shares of the Corporation. Nemesia's holdings may allow it to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as Nemesia maintains a significant interest in the Corporation, it is likely that Nemesia will exercise significant influence on the ability of the Corporation to, among other things, enter into a change in control transaction of the Corporation and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia may 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 Corporation must exercise significant judgment. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, 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 Corporation to provide reliable financial and other disclosures and to help prevent fraud. The Corporation 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 Corporation 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 Corporation'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 and the imposition of carbon taxes, 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 Corporation. In the event of a successful reassessment of the Corporation's income tax returns, such reassessment may have an impact on current and future taxes payable.

The EU previously imposed a tax on energy companies deriving income from operations in EU countries, which tax was applicable to the Group in France in 2022. Such tax could be reinstated in the future or similar taxes could be levied in other jurisdictions in which the Group operates or proposes to operate.

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 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. Future exchange rates could accordingly impact the future value of the Corporation's reserves and resources as determined by independent reserve auditors. 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 Further 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 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 favorable 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;
- Issuances or perceived issuances 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

Part I - Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information is prepared as at March 24, 2025.

Reserve 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 December 31, 2024, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, 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 Sproule's December 31, 2024 price forecasts. The preparation date of the reserves report by Sproule is January 23, 2025 and the preparation date of the contingent resource report by Sproule is January 23, 2025.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2024 price forecasts. The report by ERCE is dated January 30, 2025.

The reserve estimates, contingent resource estimates and estimate of future net revenue, and related information, including product types, in respect of IPC's oil and gas assets in Canada, France and Malaysia, based on the above-mentioned Sproule and ERCE reports, are contained in Parts II to VI below and in Schedule A.

The price forecasts used in the reserve reports are available on the website of Sproule (sproule.com), and are provided below in "Part III – Pricing Assumptions". These price forecasts are as at December 31, 2024 and may not be reflective of current and future forecast commodity prices.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE have been aggregated in this document by IPC. Estimates of reserves and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves and future net revenue for all properties, due to aggregation. This document 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 document 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.

See "Reserves and Resources Advisory" above.

The Form 51-101F2 Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor (Sproule), the Form 51-101F2 Report on Reserves Data and Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor (ERCE) and the Form 51-101F3 Report of Management and Directors on Reserves Data and Other Information are attached to this AIF as Schedules B, C and D.

Part II - Disclosure of Reserves Data

The tables below set out the reserves volumes and net present values by country. IPC's working interest volumes are reported herein as the gross reserves. The reserves adjusted for royalties or similar are reported as net reserves.

Item 2.1.1a – Breakdown of Proved Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas		Oil Equivalent	
	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross Bcf	Net Bcf	Gross MMboe	Net MMboe
Proved Developed Producing												
Canada	–	–	46.6	37.9	3.9	3.4	0.1	0.1	250.5	237.3	**92.3**	**80.8**
France	–	–	–	–	5.6	5.0	–	–	–	–	**5.6**	**5.0**
Malaysia	–	–	–	–	0.1	0.1	–	–	–	–	**0.1**	**0.1**
IPC Total	–	–	46.6	37.9	9.6	8.4	0.1	0.1	250.5	237.3	**98.0**	**85.9**
Proved Developed Non-Producing												
Canada	–	–	–	–	0.1	0.1	–	–	–	–	**0.1**	**0.1**
France	–	–	–	–	0.2	0.2	–	–	–	–	**0.2**	**0.2**
Malaysia	–	–	–	–	3.6	3.1	–	–	–	–	**3.6**	**3.1**
IPC Total	–	–	–	–	3.9	3.4	–	–	–	–	**3.9**	**3.4**
Proved Undeveloped												
Canada	197.7	161.7	66.0	51.5	3.1	2.5	0.0	0.0	2.0	1.8	**267.1**	**216.0**
France	–	–	–	–	0.5	0.4	–	–	–	–	**0.5**	**0.4**
Malaysia	–	–	–	–	–	–	–	–	–	–	–	–
IPC Total	197.7	161.7	66.0	51.5	3.6	2.9	0.0	0.0	2.0	1.8	**267.6**	**216.4**
Total Proved (1P)												
Canada	197.7	161.7	112.6	89.4	7.1	5.9	0.1	0.1	252.5	239.1	**359.6**	**297.0**
France	–	–	–	–	6.3	5.6	–	–	–	–	**6.3**	**5.6**
Malaysia	–	–	–	–	3.6	3.1	–	–	–	–	**3.6**	**3.1**
IPC Total	197.7	161.7	112.6	89.4	17.0	14.6	0.1	0.1	252.5	239.1	**369.5**	**305.6**

Item 2.1.1b – Breakdown of Proved and Probable Reserves (Forecast Case)
Breakdown of Reserves by Product Type

	Bitumen		Heavy Crude Oil		Light & Medium Oil		Natural Gas Liquids		Conventional Natural Gas		Oil Equivalent	
	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross MMbbl	Net MMbbl	Gross Bcf	Net Bcf	Gross MMboe	Net MMboe
Proved plus Probable Developed Producing												
Canada	–	–	60.4	48.9	4.8	4.1	0.1	0.1	320.2	303.3	118.7	103.6
France	–	–	–	–	7.6	6.7	–	–	–	–	7.6	6.7
Malaysia	–	–	–	–	3.3	2.8	–	–			3.3	2.8
IPC Total	–	–	60.4	48.9	15.6	13.6	0.1	0.1	320.2	303.3	129.6	113.1
Proved plus Probable Developed Non-Producing												
Canada	–	–	0.0	–	0.2	0.1	–	–	–	–	0.2	0.1
France	–	–	–	–	0.3	0.3	–	–	–	–	0.3	0.3
Malaysia	–	–	–	–	1.3	1.1	–	–	–	–	1.3	1.1
IPC Total	–	–	0.0	–	1.8	1.5	–	–	–	–	1.8	1.5
Proved plus Probable Undeveloped												
Canada	258.8	206.4	95.1	73.3	5.2	4.1	0.0	0.0	3.4	3.1	359.8	284.4
France	–	–	–	–	0.9	0.8	–	–	–	–	0.9	0.8
Malaysia	–	–	–	–	0.8	0.6	–	–	–	–	0.8	0.6
IPC Total	258.8	206.4	95.1	73.3	6.9	5.5	0.0	0.0	3.4	3.1	361.5	285.8
Total Proved plus Probable (2P)												
Canada	258.8	206.4	155.6	122.2	10.2	8.4	0.1	0.1	323.7	306.4	478.6	388.1
France	–	–	–	–	8.8	7.7	–	–	–	–	8.8	7.7
Malaysia	–	–	–	–	5.4	4.5	–	–	–	–	5.4	4.5
IPC Total	258.8	206.4	155.6	122.2	24.3	20.6	0.1	0.1	323.7	306.4	492.8	400.4
Total Probable (PB)												
Canada	61.1	44.7	43.0	32.8	3.1	2.5	0.0	0.0	71.2	67.3	119.1	91.2
France	–	–	–	–	2.5	2.2	–	–	–	–	2.5	2.2
Malaysia	–	–	–	–	1.8	1.4	–	–	–	–	1.8	1.4
IPC Total	61.1	44.7	43.0	32.8	7.3	6.0	0.0	0.0	71.2	67.3	123.3	94.7

Item 2.1.2a – Net Present Value of Future Net Revenue (Forecast Case), Proved Reserves
Breakdown of NPV by country and in aggregate Million USD

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	
Proved Developed Producing													
Canada	902.4	960.5	917.2	880.7	788.6	708.0	801.0	884.5	852.4	822.2	742.4	670.9	10.9
France	79.8	103.5	102.8	100.2	91.1	81.9	44.8	76.5	79.3	78.5	73.2	66.8	20.2
Malaysia	-31.2	-31.1	-31.0	-31.0	-30.9	-30.7	-31.7	-31.6	-31.5	-31.5	-31.4	-31.2	-469.1
IPC Total	951.0	1,032.9	989.0	949.9	848.8	759.2	814.0	929.4	900.2	869.3	784.3	706.4	11.1
Proved Developed Non-Producing													
Canada	3.3	2.5	2.2	2.0	1.7	1.4	2.5	2.0	1.7	1.6	1.3	1.1	19.3
France	3.8	3.0	2.7	2.5	2.1	1.8	2.8	2.2	1.9	1.8	1.5	1.2	12.6
Malaysia	42.7	45.8	46.9	47.5	48.3	48.4	33.5	37.9	39.7	40.7	42.3	43.2	15.5
IPC Total	49.7	51.3	51.8	52.0	52.0	51.7	38.8	42.1	43.4	44.0	45.1	45.6	15.5
Proved Undeveloped													
Canada	6,276.6	3,408.3	2,455.2	2,002.3	1,256.3	826.9	4,776.5	2,568.9	1,834.3	1,485.5	912.4	583.6	9.3
France	10.5	5.9	4.0	3.0	1.0	-0.4	7.8	3.8	2.1	1.2	-0.5	-1.6	7.6
Malaysia	–	–	–	–	–	–	–	–	–	–	–	–	–
IPC Total	6,287.1	3,414.2	2,459.3	2,005.3	1,257.4	826.6	4,784.3	2,572.7	1,836.4	1,486.8	912.0	582.0	9.3
Total Proved (1P)													
Canada	7,182.3	4,371.3	3,374.6	2,885.0	2,046.6	1,536.4	5,580.1	3,455.4	2,688.4	2,309.3	1,656.2	1,255.6	9.7
France	94.0	112.5	109.5	105.6	94.2	83.4	55.3	82.5	83.3	81.5	74.2	66.4	19.0
Malaysia	11.5	14.7	15.9	16.5	17.4	17.7	1.7	6.3	8.2	9.2	11.0	12.0	5.3
IPC Total	7,287.8	4,498.4	3,500.1	3,007.2	2,158.2	1,637.4	5,637.1	3,544.1	2,779.9	2,400.0	1,741.4	1,334.0	9.8

Item 2.1.2b – Net Present Value of Future Net Revenue (Forecast Case), Proved and Probable Reserves
Breakdown of NPV by country and in aggregate Million USD

	Before Deducting Income Tax, Discounted at						After Deducting Income Tax, Discounted at						Unit Value Before Income Tax, discounted at 10%
	0%	5%	8%	10%	15%	20%	0%	5%	8%	10%	15%	20%	
Proved plus Probable Developed Producing													
Canada	1,420.7	1,353.0	1,245.0	1,173.8	1,017.5	894.8	1,195.8	1,188.2	1,105.4	1,047.9	918.1	814.2	11.3
France	175.1	171.8	160.1	151.5	131.2	114.3	115.1	127.5	122.2	117.1	103.6	91.4	22.6
Malaysia	-0.9	4.6	7.0	8.3	10.7	12.3	-7.3	-1.0	1.8	3.4	6.4	8.5	2.9
IPC Total	1,594.8	1,529.4	1,412.1	1,333.5	1,159.4	1,021.5	1,303.6	1,314.7	1,229.5	1,168.4	1,028.1	914.1	11.8
Proved plus Probable Developed Non-Producing													
Canada	3.9	2.9	2.5	2.2	1.8	1.5	3.1	2.3	1.9	1.7	1.4	1.2	15.5
France	7.3	5.5	4.7	4.3	3.5	2.9	5.4	4.0	3.4	3.1	2.5	2.1	16.4
Malaysia	43.5	40.4	38.2	36.7	33.0	29.5	31.9	30.5	29.2	28.2	25.5	22.9	34.4
IPC Total	54.7	48.8	45.4	43.2	38.3	33.9	40.4	36.8	34.5	33.0	29.4	26.1	29.3
Proved plus Probable Undeveloped													
Canada	9,571.7	4,896.2	3,452.1	2,788.0	1,728.4	1,138.9	7,270.6	3,687.5	2,580.4	2,072.0	1,262.7	813.7	9.8
France	36.9	25.7	20.9	18.3	13.3	9.7	27.4	18.4	14.6	12.6	8.6	5.9	23.9
Malaysia	16.6	12.5	10.5	9.4	6.8	4.7	10.9	8.0	6.6	5.7	3.9	2.4	14.9
IPC Total	9,625.2	4,934.4	3,483.5	2,815.7	1,748.5	1,153.4	7,308.9	3,713.9	2,601.6	2,090.3	1,275.2	822.0	9.9
Total Proved plus Probable (2P)													
Canada	10,996.3	6,252.2	4,699.6	3,964.0	2,747.8	2,035.2	8,469.5	4,878.0	3,687.8	3,121.6	2,182.2	1,629.1	10.2
France	219.3	203.0	185.7	174.1	148.0	127.0	147.9	149.9	140.3	132.8	114.7	99.4	22.5
Malaysia	59.1	57.5	55.7	54.3	50.5	46.5	35.5	37.6	37.6	37.3	35.8	33.7	12.1
IPC Total	11,274.7	6,512.6	4,941.0	4,192.4	2,946.3	2,208.7	8,653.0	5,065.4	3,865.6	3,291.8	2,332.7	1,762.2	10.5
Total Probable (PB)													
Canada	3,814.0	1,880.9	1,325.0	1,079.0	701.2	498.9	2,889.4	1,422.6	999.3	812.3	526.0	373.5	11.8
France	125.2	90.5	76.1	68.4	53.8	43.6	92.6	67.4	56.9	51.3	40.5	33.0	31.5
Malaysia	47.7	42.8	39.8	37.8	33.1	28.8	33.8	31.3	29.4	28.1	24.9	21.8	27.4
IPC Total	3,986.9	2,014.2	1,440.9	1,185.2	788.1	571.3	3,015.9	1,521.3	1,085.7	891.7	591.3	428.2	12.5

Note: In respect of the Net Present Value (after tax, 10% discount) of total 2P reserves of USD 3,291.8 million shown in the table above, IPC calculates that the Blackrod Phase 1 project comprises approximately USD 1,400 million.

Item 2.1.3b – Elements of Future Net Revenue (Forecast Case)
Undiscounted

	Revenue Million USD	Royalties Million USD	Operating Costs Million USD	Development Costs Million USD	Abandonment Costs Million USD	Future Net Revenue Before Income Taxes Million USD	Income Taxes Million USD	Future Net Revenue After Income Taxes Million USD
Total Proved								
Canada	22,359.6	4,154.1	8,376.9	1,926.5	720.1	7,182.3	1,602.2	5,580.1
France	542.4	63.0	270.5	17.0	97.8	94.0	38.7	55.3
Malaysia	310.8	32.4	199.9	16.5	50.5	11.5	9.7	1.7
IPC Total	23,212.7	4,249.5	8,847.3	1,960.0	868.5	7,287.8	1,650.7	5,637.1
Total Proved plus Probable								
Canada	31,060.3	6,260.5	10,626.5	2,395.7	781.8	10,996.3	2,526.8	8,469.5
France	766.2	92.0	338.9	17.0	99.0	219.3	71.3	147.9
Malaysia	448.0	48.4	232.6	51.0	56.8	59.1	23.6	35.5
IPC Total	32,274.5	6,401.0	11,198.0	2,463.6	937.7	11,274.7	2,621.7	8,653.0

Item 2.1.3c – Net Present Value of Future Net Revenue (Forecast Case)
By product type, in each case including associated by-products

	Bitumen	Heavy Crude Oil	Light & Medium Crude Oil	Natural Gas	Natural Gas Liquids	Total Resources
Future Net Revenue BTAX at 10% Discount (Million USD)						
Total Proved Reserves	1,463.3	1,136.0	213.1	193.6	1.2	3,007.2
Total Proved and Probable (2P) Reserves	1,878.3	1,707.6	350.6	254.2	1.8	4,192.4
USD per boe by product type (USD/boe)						
Total Proved Reserves	9.0	12.7	14.6	0.8	17.1	9.8
Total Proved and Probable (2P) Reserves	9.1	14.0	17.0	0.8	18.1	10.5

All figures in the above table are in USD millions, unless otherwise indicated. Unit values are calculated based on net reserves volumes.

Part III – Pricing Assumptions

Forecast prices used to estimate the reserves and contingent resources figures in this document are sourced from the Sproule forecasts effective December 31, 2024.[1]

Item 3.2 – Forecast Prices Used in Estimates

	Brent (USD/bbl)	WTI Crude Oil (USD/bbl)	Canadian Light Sweet Crude (CAD/bbl)	Western Canadian Select (CAD/bbl)	Natural Gas AECO (CAD/MMbtu)	Natural Gas Empress (CAD/MMbtu)	Capital Cost Inflation Rate (%/yr)	USD/CAD Exchange Rate (USD/CAD)
Historical								
2019	64.17	57.02	68.87	58.77	1.80	2.51	0.4%	0.75
2020	43.21	39.40	45.39	35.59	2.24	2.23	-5.2%	0.75
2021	70.79	67.91	80.31	68.73	3.64	3.90	7.9%	0.80
2022	98.89	94.23	119.75	98.51	5.43	6.54	12.0%	0.77
2023	82.22	77.63	99.87	79.53	2.64	2.64	5.0%	0.74
2024	79.84	75.73	98.13	83.90	1.39	1.44	-0.3%	0.73
Forecast								
2025	75.00	71.00	97.14	83.57	2.29	3.99	0.0%	0.70
2026	80.00	76.00	100.69	87.59	3.42	4.16	2.0%	0.73
2027	80.00	76.00	97.33	84.67	3.31	3.99	2.0%	0.75
2028	81.60	77.52	99.28	86.36	3.35	4.07	2.0%	0.75
2029	83.23	79.07	101.27	88.09	3.41	4.15	2.0%	0.75
2030	84.90	80.65	103.29	89.85	3.48	4.23	2.0%	0.75
2031	86.59	82.26	105.36	91.65	3.55	4.32	2.0%	0.75
2032	88.33	83.91	107.46	93.48	3.62	4.41	2.0%	0.75
2033	90.09	85.59	109.61	95.35	3.69	4.49	2.0%	0.75
2034	91.89	87.30	111.81	97.26	3.77	4.58	2.0%	0.75
2035	93.73	89.05	114.04	99.20	3.84	4.68	2.0%	0.75
2036	95.61	90.83	116.32	101.18	3.92	4.77	2.0%	0.75
2037	97.52	92.64	118.65	103.21	4.00	4.86	2.0%	0.75
2038	99.47	94.50	121.02	105.27	4.08	4.96	2.0%	0.75
2039+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	0.75

International Currency Exchange Rate Assumptions

RATE	2025	2026	2027	2028	2029	2030 on
USD/EUR	1.00	1.00	1.00	1.00	1.00	1.00
MYR/USD	4.30	4.30	4.30	4.30	4.30	4.30

[1] *Realized pricing will reflect these reference prices with further adjustments for quality and transportation to point of sale.*

Part IV – Reconciliation of Changes in Reserves (Gross)

	Malaysia	France	Canada						IPC Total
	Light & Medium Crude Oil	Light & Medium Crude Oil	Light & Medium Crude Oil	Bitumen	Heavy Oil	NGL's	Non associated and associated Gas	Solution Gas	Oil Equivalent
	MMboe	MMboe	MMboe	MMboe	MMboe	MMboe	Bcf	Bcf	MMboe
Proved Reserves									
Opening Balance Dec 31, 2023	4.8	5.8	8.7	197.9	116.9	0.1	270.2	11.0	**381.1**
Discoveries	–	–	–	–	–	–	–	0.0	**0.0**
Extensions	–	–	–	–	0.2	0.0	–	0.2	**0.3**
Infill Drilling	–	0.5	0.3	–	0.1	0.0	–	0.0	**0.9**
Improved Recovery	–	–	–	–	–	–	–	–	**–**
Acquisitions	–	0.2	–	–	–	–	–	–	**0.2**
Dispositions	–	–	–	–	0.0	–	–	–	**0.0**
Economic factors	–	–	-0.3	–	-0.2	–	-1.1	-0.1	**-0.7**
Technical Revisions	0.2	0.7	-1.0	0.0	4.1	0.0	-2.6	5.2	**4.4**
Production	-1.4	-0.9	-0.5	-0.2	-8.5	–	-27.8	-2.5	**-16.6**
Closing Balance Dec 31, 2024	3.6	6.3	7.1	197.7	112.6	0.1	238.7	13.8	**369.5**
Probable Reserves									
Opening Balance Dec 31, 2023	1.0	3.1	2.5	20.7	46.2	–	73.9	4.4	**86.6**
Discoveries	–	–	–	–	–	–	–	0.0	**0.0**
Extensions	–	–	–	40.1	0.1	0.0	–	0.0	**40.2**
Infill Drilling	–	0.4	-0.3	–	–	0.0	–	0.0	**0.1**
Improved Recovery	–	–	–	–	–	0.0	–	–	**0.0**
Acquisitions	–	0.1	–	–	–	0.0	–	–	**0.1**
Dispositions	–	–	–	–	–	–	–	–	**–**
Economic factors	–	–	0.2	–	0.1	0.0	-0.2	0.0	**0.2**
Technical Revisions	0.7	-1.1	0.7	0.2	-3.4	0.0	-7.7	0.6	**-3.9**
Production	–	–	–	–	–	–	–	–	**–**
Closing Balance Dec 31, 2024	1.8	2.5	3.1	61.1	43.0	0.0	66.1	5.1	**123.3**
Proved plus Probable Reserves									
Opening Balance Dec 31, 2023	5.8	8.9	11.2	218.6	163.1	0.1	344.2	15.4	**467.7**
Discoveries	–	–	–	–	–	0.0	–	0.0	**0.0**
Extensions	–	–	–	40.1	0.3	0.0	–	0.3	**40.5**
Infill Drilling	0.8	0.9	–	–	0.1	0.0	–	0.0	**1.8**
Improved Recovery	–	–	–	–	–	–	–	–	**–**
Acquisitions	–	0.3	–	–	–	–	–	–	**0.3**
Dispositions	–	–	–	–	0.0	–	–	–	**0.0**
Economic factors	–	–	-0.2	0.0	-0.1	0.0	-1.3	-0.2	**-0.6**
Technical Revisions	0.1	-0.4	-0.3	0.2	0.7	0.0	-10.3	5.8	**-0.3**
Production	-1.4	-0.9	-0.5	-0.2	-8.5	0.0	-27.8	-2.5	**-16.6**
Closing Balance Dec 31, 2024	5.4	8.8	10.2	258.8	155.6	0.1	304.8	18.9	**492.8**

Part V – Additional Information Relating to Reserves Data

Item 5.1.1a, 5.1.2a – Undeveloped Reserves First Attributed by Product Type

	Proved Undeveloped			Probable Undeveloped		
	December 31, 2022	December 31, 2023	December 31, 2024	December 31, 2022	December 31, 2023	December 31, 2024
Light & Medium Crude Oil						
First Attributed (MMbbl)	0.6	0.5	0.5	0.9	0.2	1.7
YE Total (MMbbl)	5.1	4.3	3.6	2.2	1.6	3.8
Heavy Crude Oil						
First Attributed (MMbbl)	0.0	2.3	0.1	0.0	0.7	0.0
YE Total (MMbbl)	63.1	70.2	66.0	29.0	31.6	29.2
Bitumen						
First Attributed (MMbbl)	197.8	0.0	0.0	20.7	0.0	40.1
YE Total (MMbbl)	197.8	197.9	197.7	20.7	20.7	61.1
Conventional Natural Gas						
Non-Associated and Associated Gas						
First Attributed (MMcf)	0.0	0.0	0.0	0.0	0.0	0.0
YE Total (MMbbl)	0.0	0.0	0.0	0.0	0.0	0.0
Solution Gas						
First Attributed (MMcf)	0.0	2.3	0.0	0.0	1.6	0.0
YE Total (MMcf)	0.8	2.7	2.0	0.4	1.8	1.5
Natural Gas Liquids						
First Attributed (MMbbl)	0.0	0.0	0.0	0.0	0.0	0.0
YE Total (MMbbl)	0.0	0.0	0.0	0.0	0.0	0.0
Total						
First Attributed (MMboe)	**198.4**	**3.3**	**0.5**	**21.7**	**2.2**	**41.9**
YE Total (MMboe)	**266.1**	**272.8**	**267.6**	**52.0**	**54.2**	**94.3**

Reserves development forecasts documented in this disclosure are consistent with COGE Handbook recommended guidance regarding the development of undeveloped petroleum and natural gas volumes as follows:

1. three years for the assignment of proved reserves and five years for the assignment of probable reserves in conventional development properties,
2. five years for the assignment of proved reserves and ten years for the assignment of probable reserves in resource play development properties
3. for the heavy oil thermal project in the Onion Lake area, future development has been scheduled to optimize operations and deliver supply at design capacity for the life of the central processing facility. In respect of Onion Lake Thermal, see also above "**Description of the Business - Description of the Group's Oil and Gas Assets – Canada – Onion Lake Thermal**".
4. for the bitumen thermal project in the Blackrod area, future development has been scheduled to optimize the phasing of the project to meet the first oil date. In respect of development of Phase 1 of the Blackrod area, see also above "**Description of the Business - Description of the Group's Oil and Gas Assets – Canada – Blackrod**".

Item 5.2 – Significant Factors or Uncertainties Affecting Reserves Data

See "Cautionary Statement regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors" above.

In Canada, the main uncertainties at Suffield relate to performance of future infill wells and the continued effectiveness of the polymer injection in mobilizing bypassed oil. At Onion Lake Thermal, the main uncertainties include the performance of future drilling pads and the effectiveness of steam propagation. At Blackrod, the main uncertainties include the project development schedule and the performance of future drilling pads and the effectiveness of steam propagation. These uncertainties are captured in the 1P to 2P range of estimates. Other uncertainties that affect the Canadian properties include weather related downtime, facility performance, effectiveness of Suffield gas optimization investments and performance of development drilling at Ferguson. The abandonment liability beyond what has been considered in the reserve assessment is not material to the Canadian asset valuation. These assets are not expected to have higher than reported costs or onerous contractual obligations that would impair the Group's realized values.

In France, the main uncertainties are the reservoir performance in the water flooded Triassic formation pools and performance of the recent Villeperdue West development wells. These uncertainties have been captured in the 1P to 2P range of estimates. There are no material abandonment costs, excessive costs or contractual obligations, other than what has been considered in the reserves assessment, that would impair the Group's realized values. 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 and probable reserves assume a cessation of production as at year end 2039, to reflect the uncertainties regarding the application of this new legislation.

In Malaysia, the main uncertainties, which have been captured in the 1P to 2P range of estimates, include, water cut development in the producing wells, facility uptime performance, electric submersible pump performance and operating cost performance. There are no material abandonment costs, excessive costs or contractual obligations, other than what has been considered in the reserves assessment, that would impair the Group's realized values.

Item 5.3 Future Development Costs Million USD

	2025	2026	2027	2028	2029	2030 on	Total for all years undiscounted	Total for all years discounted at 10% p.a.
Total Proved								
Canada	239.7	86.0	41.1	122.4	56.4	1,380.9	1,926.5	909.5
France	4.9	12.0	–	–	–	–	17.0	15.3
Malaysia	16.5	–	–	–	–	–	16.5	16.4
Total	261.2	98.0	41.1	122.4	56.4	1,380.9	1,960.0	941.3
Total Proved Plus Probable								
Canada	242.1	89.6	118.2	176.7	33.4	1,735.8	2,395.7	1,062.0
France	4.9	12.0	–	–	–	–	17.0	15.3
Malaysia	18.0	33.0	–	–	–	–	51.0	50.3
Total	265.0	134.7	118.2	176.7	33.4	1,735.8	2,463.6	1,127.7

All figures in the above table are in USD millions, unless otherwise indicated.

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 document. 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.

Part VI – Other Oil and Gas Information

Item 6.1 – Oil and Gas Properties and Wells

The assets described in this report are located in Canada, France and Malaysia. The Canadian assets are located in Alberta and Saskatchewan. The French and Canadian assets are exclusively located onshore. The Malaysian asset is located offshore.

	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	8	8	9	9	-	-	-	-
France	105	99	67	64	-	-	-	-
Canada	877	855	504	490	11,397	10,973	238	199

Item 6.2 – Properties with no attributed reserves

							Outstanding Work Commitments					
Country	Property	Operator	W.I.	Location	Gross Area ha	Net Area ha	Nature of Outstanding Commitment	Detail of Work Commitment	Gross Amount USD	Amount planned in 2025 Towards Commitments USD	Amount planned after 2025 Towards Commitments USD	End of Commitment Period
France	Plivot	IPC	100.0%	Onshore	19,800	19,800	None	-	-	-	-	-
Canada	Portage	IPC	62.2%	Onshore	36,352	22,594	None	-	-	-	-	-

Item 6.2.1 –Significant factors or uncertainties relevant to properties with no attributed reserves

None of the properties listed with no attributed reserves have significant abandonment and reclamation costs, unusually high expected development or operating costs, or onerous contractual obligations.

Item 6.5 – Tax Horizon

In Canada, as of January 1, 2025, IPC has depreciable tax pools brought forward of CAD 1,016 million as well as tax loss carry forward balances of CAD 244 million. Based on current assumptions and forecasts, IPC expects no cash taxes to be paid in Canada during 2025.

In Malaysia, the Corporation has a significant cost recovery balance of USD 316 million as of January 1, 2025. IPC has depreciable tax pools of USD 12 million.

IPC pays current taxes in France and Malaysia. The tax rate is 25% in both countries.

Item 6.6 – Costs Incurred

	2024 Costs Incurred, in USD millions			
	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
France	-	-	0.0	3.5
Malaysia	-	-	1.4	17.0
Canada	-	-	0.5	412.3
Total	-	-	1.9	432.8

Item 6.7.1 – Exploration and Development Activity

	2024 Exploration Activity Summary, wells completed					
	France		Malaysia		Canada	
	Gross	Net	Gross	Net	Gross	Net
Wells completed	-	-	-	-	22	22
Completed as						
Oil well	-	-	-	-	12	12
Gas well	-	-	-	-	-	-
Service well	-	-	-	-	9	9
Stratigraphic test well	-	-	-	-	1	1
Dry hole	-	-	-	-	-	-

	2024 Development Activity Summary, wells completed					
	France		Malaysia		Canada	
	Gross	Net	Gross	Net	Gross	Net
Wells completed	-	-	-	-	12	12
Completed as						
Oil well	-	-	-	-	6	6
Gas well	-	-	-	-	-	-
Service well	-	-	-	-	6	6
Stratigraphic test well	-	-	-	-	-	-
Dry hole	-	-	-	-	-	-

The recent development activity by field is summarised below. Where additional development potential has been identified it is discussed further in the Statement of Contingent Resources (Unrisked) contained in **Schedule A** of this AIF.

Canada

Blackrod

The Phase 1 development was sanctioned in Q1 2023. Project execution activities, including site preparation, facility construction and development well drilling, progressed according to plan and budget during 2024.

Suffield Area

During 2024, eight wells were drilled, completed and brought onto production. Optimization of existing gas well inventory covers a range of activities including pulling of siphon strings, adding new completion intervals, and re-fracturing existing completions.

Ferguson

During 2024, five wells were drilled, completed and brought onto production.

Item 6.8 – 2025 Forecast Saleable Production Estimates in Reserves Report

	Light & Medium Oil Mbbl/d	Heavy Crude Oil Mbbl/d	Conventional Natural Gas Mboe/d	Natural Gas Liquids Mboe/d	Total Oil Equivalent Mboe/d
Total Proved (1P) Scenario					
Canada	1.5	20.2	13.1	0.0	**34.8**
France	2.0	–	–	–	**2.0**
Malaysia	2.5	–	–	–	**2.5**
Total	6.0	20.2	13.1	0.0	**39.3**
Total Proved plus Probable (2P) Scenario					
Canada	1.6	22.4	13.4	0.0	**37.4**
France	2.3	–	–	–	**2.3**
Malaysia	2.6	–	–	–	**2.6**
Total	6.5	22.4	13.4	0.0	**42.3**

Item 6.9 – Wellhead production history by quarter for most recent financial year split by product type and average netbacks

	Q1 24	Q2 24	Q3 24	Q4 24	2024
Canada – Light and Medium Crude Oil					
Production, Mbopd	1.2	1.4	1.6	1.4	**1.4**
Unit Volume Average (USD/boe)					
Prices received	61.8	69.9	67.0	64.2	**65.9**
Royalties paid	16.2	14.0	15.9	14.3	**15.1**
Production costs	24.2	14.4	22.9	17.7	**19.8**
Netback	21.5	41.5	28.2	32.2	**31.1**
Canada - Heavy Crude Oil					
Production, Mbopd	24.9	24.3	21.9	24.3	**23.9**
Unit Volume Average (USD/boe)					
Prices received	70.6	74.9	69.3	66.9	**70.4**
Royalties paid	9.1	13.3	11.4	9.2	**10.7**
Production costs	37.7	34.0	33.9	34.7	**35.1**
Netback	23.7	27.6	24.0	23.0	**24.6**
Canada – Conventional Natural Gas					
Production, Mboepd	16.0	16.1	15.3	16.0	**15.8**
Unit Volume Average (USD/boe)					
Prices received	10.4	4.8	3.4	6.6	**6.3**
Royalties paid	0.2	0.3	0.1	0.4	**0.3**
Production costs	7.5	6.3	7.4	6.7	**7.0**
Netback	2.7	-1.8	-4.1	-0.5	**-0.9**
Canada – (Oil & Gas)					
Production, Mboepd	42.1	41.8	38.9	41.8	**41.1**
Unit Volume Average (USD/boe)					
Prices received	50.5	51.4	46.6	46.9	**48.9**
Royalties paid	6.4	9.0	7.7	6.4	**7.4**
Production costs	27.4	24.1	24.4	24.9	**25.2**
Netback	16.7	18.3	14.5	15.6	**16.3**
Malaysia – Light & Medium Crude Oil					
Production, Mbopd	4.1	4.1	3.7	3.5	**3.8**
Unit Volume Average (USD/boe)					
Prices received	49.2	106.4	53.0	91.4	**74.9**
Royalties paid	0.0	0.0	0.0	0.0	**0.0**
Production costs	5.2	32.6	16.7	43.5	**24.0**
Netback	44.0	73.8	36.4	47.8	**50.9**
France – Light & Medium Crude Oil					
Production, Mbopd	2.5	2.6	2.4	2.1	**2.4**
Unit Volume Average (USD/boe)					
Revenue	86.6	83.6	78.0	76.3	**81.4**
Royalties paid	5.0	4.9	5.2	4.2	**4.8**
Production costs	38.5	32.9	36.9	53.7	**40.0**
Netback	43.2	45.8	35.9	18.3	**36.6**
IPC Total – Oil Equivalent					
Production, Mboepd	48.8	48.4	45.0	47.4	**47.4**
Unit Volume Average (USD/boe)					
Prices received	52.3	57.8	48.8	51.5	**52.7**
Royalties paid	5.8	8.0	7.0	5.9	**6.7**
Production costs	26.1	25.3	24.4	27.5	**25.8**
Netback	20.4	24.4	17.5	18.1	**20.2**

Netbacks reflected in the table above are with respect to wellhead production volumes.

DIVIDENDS AND DISTRIBUTIONS

The Corporation does not currently pay cash dividends on the Common Shares.

During 2024, the Corporation continued and renewed its normal course issuer bid / share repurchase program (NCIB). IPC believes that the NCIB represent an effective use of IPC's capital and is an efficient way to return value to IPC's shareholders.

During the period of December 5, 2023 to December 4, 2024, IPC purchased and cancelled an aggregate of approximately 8.3 million Common Shares under the 2023/2024 NCIB. In December 2024, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 7.5 million Common Shares over the period of December 5, 2024 to December 4, 2025. Under the 2024/2025 NCIB, IPC repurchased for cancellation approximately 0.8 million common shares in December 2024 and a further approximately 3.6 million Common Shares from January 1, 2025 up to March 21, 2025. All Common Shares repurchased by IPC under the NCIB have been, or will be, cancelled.

Any decision to pay cash 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 119,169,471 were issued and outstanding as at December 31, 2024 and of which 116,409,568 are issued and outstanding 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, 2024 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 share unit plan ("**Share Unit Plan**"), under which awards have been made, and are expected to be made in the future, in performance share units ("**IPC PSU**") or in restricted share units ("**IPC RSU**"); and a stock option plan ("**Stock Option Plan**").

For the IPC PSUs, awards are subject to continued employment and to certain performance conditions being met. The IPC PSUs will vest after three years based as to 75% based on a calculation of comparative total shareholder return (TSR) relative to a peer group of international oil and gas companies. For the IPC RSUs, awards to employees are subject to continued employment. The awards which vest over three years as to one-third each year. In addition, non-employee directors of the Corporation may elect for IPC RSUs for all or a portion of the fee payable for services performed as a director and otherwise payable in cash. These awards vest immediately at the time of grant, although these awards may not be redeemed before the end of service as a director of the Corporation. IPC had an aggregate of 3,325,568 awards of IPC PSUs and IPC RSUs outstanding as at December 31, 2024.

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. As at the date of this AIF, no stock options are outstanding under the Stock Option Plan.

Bonds

In February 2022, IPC completed a private placement of USD 300 million of senior unsecured bonds. The bonds have a tenor of five years and a fixed coupon rate of 7.25 percent per annum, with interest payable in semi-annual instalments. The bond issue was rated B+ by S&P Global Ratings and B1 by Moody's.

In September 2023, IPC completed a tap issue of USD 150 million under IPC's existing senior unsecured bond framework, issued at 7% discount to par value and therefore with net proceeds amounting to USD 139.5 million. Following the tap issue and as at the date of this AIF, IPC has USD 450 million of senior unsecured bonds outstanding with maturity in February 2027.

Credit Facilities

As at December 31, 2024, the Group had a revolving credit facility (RCF) of CAD 180 million in connection with its oil and gas assets in Canada. No amounts were drawn under the Canadian RCF as at December 31, 2024. During 2024, the Group entered into a letter of credit facility in Canada (LC Facility) to cover existing operational letters of credit. As at December 31, 2024, operational letters of credit in an aggregate of CAD 40.2 million were issued under the LC Facility, As at December 31, 2024, IPC had an unsecured credit facility in France, with maturity in May 2026. The amount remaining outstanding this facility as at December 31, 2024 was EUR 5.1 million.

Credit Ratings

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. A credit rating is not a recommendation to buy, sell or hold securities and does not address the market price or suitability of a specific security for a particular investor. Such ratings may be subject to revision or withdrawal at any time by the respective credit rating agency and each rating should be evaluated independently of any other rating.

	S&P Global Rating	Moody's Rating
IPC senior unsecured bonds	B+	B1

S&P Global

The B rating assigned by S&P is the seventh highest rating of S&P's 10 rating categories for long-term debt, which range from AAA to D. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. Debt securities rated B are judged by S&P to have the capacity to meet its financial commitments on the obligation. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet such financial commitments.

Moody's

The B rating assigned by Moody's is the sixth highest rating of Moody's nine rating categories for long-term debt, which range from Aaa to C. Moody's appends numerical modifiers from one to three on its long-term debt ratings from Aa to Caa to indicate where the obligation ranks within a particular ranking category, with the two modifier indicating a mid-range ranking. A modifier of one indicates that the obligation ranks on the higher end of its generic rating category and a modifier of three indicates that the obligation ranks on the lower end of its generic rating category. Obligations rated B are defined by Moody's as considered speculative and are subject to high credit risk. They are considered non-investment grade.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed for trading on the TSX in Canada and the Nasdaq Stockholm in Sweden under the trading symbol "IPCO".

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

Month (2024)	High (CA$)	Low (CA$)	Volume
January	16.01	14.37	817,517
February	15.65	13.36	1,779,678
March	16.24	14.49	974,961
April	18.17	15.98	1,478,824
May	19.19	16.85	1,834,910
June	19.13	17.07	1,478,596
July	20.59	18.85	1,153,332
August	20.45	17.91	1,138,244
September	19.09	15.30	1,429,409
October	18.17	15.61	1,908,541
November	16.25	14.42	1,913,195
December	16.85	15.04	1,495,074

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

Month (2024)	High (SEK)	Low (SEK)	Volume
January	123.35	111.70	3,958,252
February	120.95	100.10	5,476,584
March	127.30	107.65	4,078,238
April	144.20	129.00	3,736,426
May	151.40	133.10	3,464,313
June	147.80	130.80	3,252,846
July	158.80	140.50	3,281,277
August	157.90	134.10	2,724,192
September	150.00	114.40	3,926,454
October	139.10	117.70	5,143,069
November	127.80	112.20	4,159,306
December	126.70	115.10	2,448,956

Prior Sales

There were no issuances of Common Shares in 2024.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2024 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

The names, residence, position with the Corporation, period served as a director, number of Common Shares beneficially owned or controlled and principal occupation during the five preceding years of our directors and executive officers as of the date of this AIF are set out below.

Name and Province and Country of Residence	Position with the Corporation[5]	Number of Common Shares Beneficially Owned or Controlled	Principal Occupation
William Lundin[8] Switzerland	President and Chief Executive Officer, Director (since January 2024)	731,702	President and Chief Executive Officer of the Corporation since January 2024; Chief Operating Officer of the Corporation from December 2020 to December 2023; Project management positions with IPC Canada Ltd. since December 2018
C. Ashley Heppenstall[1][2] United Kingdom	Chair of the Board, Director (since March 2017)	1,127,501[6]	Corporate Director
Chris Bruijnzeels[3][4] The Netherlands	Director (since March 2017)	50,000	Corporate Director
Donald Charter[1][2][4] Ontario, Canada	Director (since March 2017)	72,333	Businessman
L.H. (Harry) Lundin Ontario, Canada	Director (since May 2020)	185,100[7]	Chief Executive Officer of Bromma Asset Management Inc.
Emily Moore[2][3] Ontario, Canada	Director (since May 2021)	19,770 Director RSUs	Associate Professor and Director, Troost Institute for Leadership Education in Engineering (ILead), University of Toronto Faculty of Applied Science and Engineering since October 2018
Mike Nicholson[3] Monaco	Director (since February 2017)	550,000	President and CEO of the Corporation from April 2017 to December 2023
Deborah Starkman[1][4] Ontario, Canada	Director (since November 2023)	4,468 Director RSUs	Chief Financial Officer of Dream Unlimited Corp. from 2020 to March 2024; Chief Financial Officer and Corporate Secretary of GMP Capital Inc. from 2012 until 2020
Christophe Nerguararian[8] Switzerland	Chief Financial Officer	500,000	CFO of the Corporation since April 2017
Nicki Duncan[8] Switzerland	Chief Operating Officer	2,000	COO of the Corporation since January 2024; Group Operations Manager of the Corporation from February 2018 to December 2023
Jeffrey Fountain[8] Switzerland	General Counsel and Corporate Secretary	445,679	General Counsel and Corporate Secretary of the Corporation since April 2017
Rebecca Gordon[8] Switzerland	Senior Vice President Corporate Planning and Investor Relations	53,962	Senior Vice President Corporate Planning and Investor Relations of the Corporation since February 2024; Vice President Corporate Planning and Investor Relations of the Corporation from April 2017 to February 2024
Chris Hogue[8] Alberta, Canada	Senior Vice President Canada	1,074,454	Senior Vice President Canada of the Corporation since December 2018
Ryan Adair Alberta, Canada	Vice President Asset Management and Corporate Planning Canada	72,325	Vice President Asset Management and Corporate Planning Canada since April 2019
Curtis White Alberta, Canada	Vice President Commercial Canada	12,167	Vice President Commercial Canada since February 2024; Director, Marketing and Business Development, IPC Canada Ltd. from June 2019 to February 2024

Notes:
1. *(1) Member of Audit Committee.*
2. *(2) Member of Compensation Committee.*
3. *(3) Member of Reserves and Sustainability Committee.*
4. *(4) Member of Nominating and Corporate Governance Committee.*
5. *(5) Each of the Directors was appointed at the Annual General Meeting of Shareholders in May 2024 for a term until the next Annual General Meeting of Shareholders, to be held in May 2025, unless the directorship is earlier vacated in accordance with the Articles of the Corporation or the Business Corporations Act (British Columbia) or he or she becomes disqualified to act as a director.*
6. *(6) Rojafi, an investment company owned by Mr. Heppenstall and his family, holds 1,127,501 Common Shares.*
7. *(7) Bromma Asset Management Inc., of which Mr. Lundin is majority owner and CEO, has control and direction over 185,100 Common Shares.*
8. *(8) Member of the Executive Committee and a "Person Discharging Managerial Responsibilities" for purposes of the Market Abuse Regulation.*

As at March 24, 2025, the directors and executive officers of the Corporation, as a group, beneficially owned, or directed or controlled, directly or indirectly, including through investment or controlled companies as noted above, approximately 4.9 million Common Shares or approximately 4.2% of the total number of issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No 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 AIF, 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.

No 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 AIF, 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.

No 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 AIF, 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 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 and Related Party Transactions

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 are members of the Board or executive officers of the Corporation, other than in respect of L.H. (Harry) Lundin and William Lundin. The Board believes that their family relationship as brothers does not adversely affect the proper functioning and independence of the Board as a whole.

Where a conflict or potential conflict is identified or a related party transaction is brought to the Board’s attention, the full Board will assess the proposed related party transaction and/or circumstances involving a potential conflict of interest. If the matter is one that is required under applicable corporate or securities laws to be dealt with by a subset of the Board or a special committee consisting solely of independent directors or where the Board otherwise determines that the formation of such a committee is necessary or advisable, the relevant arrangements are made. In such a circumstance, all conflicted or potentially conflicted directors are required to recuse themselves and will abstain from voting on any resolutions, with only non-conflicted directors entitled to engage in substantive discussion, receive transaction evaluation materials and vote on such matters.

As at December 31, 2024 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 E.

Composition of the Audit Committee

The Audit Committee is currently comprised of C. Ashley Heppenstall (Chair), Donald Charter and Deborah Starkman, 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 has been 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.

Ms. Starkman holds a Chartered Professional Accountant designation (FCPA, FCA) in Canada and is a Chartered Financial Analyst (CFA). She previously served as Chief Financial Officer of a major publicly listed Canadian company and, before that, was CFO of a Canadian financial services firm. She holds a Bachelor of Commerce degree from the University of Windsor and a Bachelor of Arts from the University of Western Ontario. With extensive experience in financial management, reporting, and oversight in public companies, she brings deep expertise in governance, risk management, and financial strategy. She is also a member of the Institute of Corporate Directors (ICD.D).

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 SA in the year ended December 31, 2023 and by PricewaterhouseCoopers LLP in the year ended December 31, 2024 in USD thousands.

Financial Year Ending	Audit Fees (1)	Audit Related Fees (2)	Tax Fees (3)	All Other Fees (4)
2023	707	198	–	–
2024	708	199	–	–

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

The Corporation has had no promoters within the two most recently completed financial years or during the current financial year.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal proceedings

During the year ended December 31, 2024 and until the date of this AIF, 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 such contemplated proceedings.

Regulatory actions

During the year ended December 31, 2024 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 AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares in Canada is Computershare Investor Services Inc., and the Common Shares are transferable at the offices of Computershare in Toronto and Calgary.

MATERIAL CONTRACTS

There are no 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, or entered into prior to such date but which contracts are still in effect.

NAMES AND INTERESTS OF EXPERTS

This AIF contains references to estimates of reserves, contingent 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 Canada are effective as of December 31, 2024, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, 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).

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2024, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook.

Neither of ERCE and Sproule, 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 linked to the 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.

PricewaterhouseCoopers LLP, Professional 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.

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 management 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.sedarplus.ca and on the Corporation's website at www.international-petroleum.com.

SCHEDULE A – CONTINGENT RESOURCES DATA

Working Interest Contingent Resources Unrisked

	Technology	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMcf			NGL Mbbl			Total Oil Equivalent Mboe			Chance of Development	Economic Sub Class	Project Maturity	Project Evaluation	Working Interest
		1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C					
Malaysia Bertam																								
NFA	Established	-	1,079	2,390													-	1,079	2,390	25%	Economic	Development Unclarified	Conceptual	100%
Infill Wells	Established	586	698	789													586	698	789	50%	Undetermined	Development Unclarified	Conceptual	100%
France Paris Basin																								
Amaltheus	Established	143	679	1,217													143	679	1,217	50%	Undetermined	Development Unclarified	Conceptual	100%
Amaltheus Post 2040	Established	5	14	52													5	14	52	45%	Undetermined	Development on Hold	Advanced	100%
Courdemanges	Established	278	1,512	2,638													278	1,512	2,638	50%	Undetermined	Development Unclarified	Conceptual	100%
Courdemanges Post 2040	Established	43	107	250													43	107	250	45%	Undetermined	Development on Hold	Advanced	100%
Dommartin Lettree	Established	193	451	796													193	451	796	50%	Undetermined	Development Unclarified	Conceptual	43.01%
Dommartin Lettree Post 2040	Established	83	204	331													83	204	331	45%	Undetermined	Development on Hold	Advanced	100%
Fontaine au Bron	Established	350	700	1,200													350	700	1,200	50%	Undetermined	Development Unclarified	Conceptual	100%
Fontaine au Bron post 2040	Established	193	532	952													193	532	952	45%	Undetermined	Development on Hold	Advanced	100%
Genievre	Established	-	44	211													-	44	211	50%	Undetermined	Development Unclarified	Conceptual	100%
Genievre Post 2040	Established	3	10	42													3	10	42	45%	Undetermined	Development on Hold	Advanced	100%
Grandville	Established	-	963	1,527													-	963	1,527	50%	Undetermined	Development Unclarified	Conceptual	100%
Grandville Post 2040	Established	295	815	1,346													295	815	1,346	45%	Undetermined	Development on Hold	Advanced	100%
Hautefeuille Post 2040	Established	-	6	51													-	6	51	45%	Undetermined	Development on Hold	Advanced	100%
La Motte Noir Post 2040	Established	-	41	68													-	41	68	45%	Undetermined	Development on Hold	Advanced	100%
Merisier	Established	589	2,572	4,001													589	2,572	4,001	50%	Undetermined	Development Unclarified	Conceptual	100%
Merisier Post 2040	Established	-	-	92													-	-	92	45%	Undetermined	Development on Hold	Advanced	100%
Soudron	Established	820	1,713	2,847													820	1,713	2,847	50%	Undetermined	Development Unclarified	Conceptual	100%
Soudron Post 2040	Established	167	562	982													167	562	982	45%	Undetermined	Development on Hold	Advanced	100%
Vert La Gravelle	Established	250	500	1,000													250	500	1,000	50%	Undetermined	Development Unclarified	Conceptual	100%
Vert La Gravelle Post 2040	Established	121	402	794													121	402	794	45%	Undetermined	Development on Hold	Advanced	100%
Villeperdue West Phase 2	Established	1,707	2,845	3,983													1,707	2,845	3,983	30%	Undetermined	Development Unclarified	Conceptual	100%
Villeperdue North East	Established	600	1,000	1,400													600	1,000	1,400	30%	Undetermined	Development Unclarified	Conceptual	100%
Villeperdue Well P18	Established	200	500	800													200	500	800	50%	Undetermined	Development Unclarified	Conceptual	100%
Villeperdue Post 2040	Established	1,279	1,954	2,886													1,279	1,954	2,886	45%	Undetermined	Development on Hold	Advanced	100%
Villeseneux	Established	-	249	244													-	249	244	50%	Undetermined	Development Unclarified	Conceptual	100%
Villeseneux Post 2040	Established	4	75	261													4	75	261	45%	Undetermined	Development on Hold	Advanced	100%
France Aquitaine Basin																								
Courbey	Established	1,300	2,150	3,700													1,300	2,150	3,700	50%	Undetermined	Development Unclarified	Conceptual	50%
Courbey Post 2040	Established	297	521	771													297	521	771	45%	Undetermined	Development on Hold	Advanced	50%
Les Arbousiers Post 2040	Established	-	-	173													-	-	173	45%	Undetermined	Development on Hold	Advanced	50%
Les Mimosas Post 2040	Established	30	110	244													30	110	244	45%	Undetermined	Development on Hold	Advanced	50%
Les Pins Post 2040	Established	-	-	256													-	-	256	45%	Undetermined	Development on Hold	Advanced	50%
Tamaris 2040	Established	-	34	64													-	34	64	45%	Undetermined	Development on Hold	Advanced	50%
Canada																								
Suffield Oil Mannville	Established				960	1,305	1,650				99	135	169	1	1	1	977	1,328	1,679	70%	Undetermined	Development On Hold	Level II/III	100%
Suffield Oil Detrital	Established				350	500	650				32	45	58	0	0	0	356	508	660	70%	Undetermined	Development On Hold	Level II	100%
Suffield Gas Infills	Established										105,067	195,124	285,181				17,511	32,521	47,530	50%	Undetermined	Development On Hold	Level II	100%
Suffield Gas Recompletes	Established										7,032	13,312	18,720				1,172	2,219	3,120	69%	Undetermined	Development On Hold	Level II	100%
Alderson Gas Infills	Established										20,513	34,188	47,863				3,419	5,698	7,977	50%	Undetermined	Development On Hold	Level II	100%
Alderson Gas Recompletes	Established										1,152	1,536	2,160				192	256	360	69%	Undetermined	Development On Hold	Level II	100%
Mooney	Established				6,121	8,187	11,286										6,121.00	8,187.00	11,286.00	71%	Economic	Development On Hold	Level III	100%
Blackrod - Phase II and III	Established							967,524	1,025,356	1,120,054							967,524	1,025,356	1,120,054	77%	Economic	Development On Hold	Level II/III	100%
Ferguson Gas Flood Blowdown	–										8,400	12,000	15,600	193	276	359	1,593	2,276	2,959	70%	Economic	Development Unclarified	Level III	100%
Ferguson Gas Flood Optimization	–	968	2,027	3,546													968	2,027	3,546	70%	Economic	Development Unclarified	Level III	100%
Onion Lake Thermal	Established				3,805	3,950	14,413										3,805	3,950	14,413	85%	Economic	Development On Hold	Level III	100%

Working Interest Contingent Resource Development Unclarified Status (Risked and Unrisked)

	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMcf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Unrisked																		
Malaysia	586	1,777	3,179													**586**	**1,777**	**3,179**
France	6,429	15,877	25,563													**6,429**	**15,877**	**25,563**
Canada	968	2,027	3,546							8,400	12,000	15,600	193	276	359	**2,561**	**4,303**	**6,505**
Total Unrisked	7,984	19,681	32,288							8,400	12,000	15,600	193	276	359	**9,577**	**21,957**	**35,247**
Subtotal by Country Risked by Chance of Development																		
Malaysia	293	619	992													**293**	**619**	**992**
France	2,753	7,170	11,705													**2,753**	**7,170**	**11,705**
Canada	678	1,419	2,482							5,880	8,400	10,920	135	193	251	**1,793**	**3,012**	**4,554**
Total Risked	3,724	9,207	15,179							5,880	8,400	10,920	135	193	251	**4,839**	**10,800**	**17,251**

Working Interest Contingent Resource Development on Hold Status (Risked and Unrisked)

	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMcf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Unrisked																		
Malaysia	-	-	-													**–**	**–**	**–**
France	2,519	5,385	9,614													**2,519**	**5,385**	**9,614**
Canada	-	-	-	11,236	13,942	27,999	967,524	1,025,356	1,120,054	133,895	244,340	354,151	1	1	1	**1,001,077**	**1,080,022**	**1,207,079**
Total Unrisked	2,519	5,385	9,614	11,236	13,942	27,999	967,524	1,025,356	1,120,054	133,895	244,340	354,151	1	1	1	**1,003,595**	**1,085,407**	**1,216,693**
Subtotal by Country Risked by Chance of Development																		
Malaysia	-	-	-													**-**	**-**	**-**
France	1,133	2,423	4,326													**1,133**	**2,423**	**4,326**
Canada	-	-	-	8,497	10,433	21,874	744,993	789,524	862,441	68,529	125,027	181,088	1	1	1	**764,913**	**820,796**	**914,498**
Total Risked	1,133	2,423	4,326	8,497	10,433	21,874	744,993	789,524	862,441	68,529	125,027	181,088	1	1	1	**766,046**	**823,219**	**918,824**

Working Interest Contingent Resource Grand Totals (Risked and Unrisked)

	Light Crude Oil & Medium Crude Oil Mbbl			Heavy Crude Oil Mbbl			Bitumen Mbbl			Conventional Natural Gas MMcf			NGL Mbbl			Total Oil Equivalent Mboe		
	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C	1C	2C	3C
Unrisked																		
Malaysia	586	1,777	3,179													**586**	**1,777**	**3,179**
France	8,948	21,262	35,177													**8,948**	**21,262**	**35,177**
Canada	968	2,027	3,546	11,236	13,942	27,999	967,524	1,025,356	1,120,054	142,295	256,340	369,751	194	277	360	**1,003,638**	**1,084,324**	**1,213,585**
Total Unrisked	10,502	25,066	41,902	11,236	13,942	27,999	967,524	1,025,356	1,120,054	142,295	256,340	369,751	194	277	360	**1,013,172**	**1,107,364**	**1,251,941**
Subtotal by Country Risked by Chance of Development																		
Malaysia	293	619	992													**293**	**619**	**992**
France	3,887	9,593	16,031													**3,887**	**9,593**	**16,031**
Canada	678	1,419	2,482	8,497	10,433	21,874	744,993	789,524	862,441	74,409	133,427	192,008	136	194	252	**766,705**	**823,808**	**919,052**
Total Risked	4,857	11,630	19,506	8,497	10,433	21,874	744,993	789,524	862,441	74,409	133,427	192,008	136	194	252	**770,885**	**834,019**	**936,075**

The volumes in the table above are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of contingent resources and appreciate the differing probabilities of recovery associated with each class.

The working interest (gross) contingent resource volumes (unrisked and risked) are reported in the above tables for each product type, and classified in each applicable project maturity sub-class. The net present value of future net revenue of the contingent resource estimates has not been prepared and therefore, the net contingent resources volumes are not reported.

Project descriptions for IPC's contingent resource estimates are provided as follows, noting that in respect of all statements with respect to future potential activities and estimated costs and timing, see "**Cautionary Statement regarding Forward-Looking Information**", "**Reserves and Resources Advisory**" and "**Risk Factors**" above:

France

The Contingent Resource estimates reported for France relate to development drilling, waterflood optimization opportunities and volumes produced beyond December 31, 2039, the date at which, under French law, hydrocarbon production must cease. In all cases, the product type is light crude oil. The technical risks and uncertainties associated with the Contingent Resources in France linked to further development relate to limited seismic coverage and understanding of the 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. Such Contingent Resources have been classed as Development Unclarified. For those Contingent Resources associated with the petroleum law to become Reserves, it would be necessary for the government to issue a repeal, or for the appeal of an operator to be won, or for new projects to be identified to accelerate hydrocarbon recovery. These volumes are classed as Development on Hold. Where an economic limit occurs before December 31, 2039, no Contingent Resources associated with production beyond December 31, 2039 are assigned in that category. In instances where the economic limit is encountered due to the French hydrocarbon law, and for Contingent Resources associated with future development projects, economics have not been run and so those volumes may include a portion that is sub-economic to produce.

Malaysia

Contingent Resources estimates for Malaysia comprise volumes produced beyond the reserves cut off and the drilling of an infill well. The drilling of the infill well is contingent upon economic and technical feasibility studies, with the project development timing within the next 5 years. All Malaysia Contingent Resources are classed as Development Unclarified. Economics have been run on the production beyond the reserves cut off, so only economic Contingent Resources have been reported. Economics have not been run on the Contingent Resources associated with the infill well and so those volumes may include a portion that is sub-economic to produce.

Canada

Suffield Area

The contingent shallow gas resources in the Suffield area are attributed to development drilling and recompletes. The development is expected to be phased and consists of drilling vertical commingled wells and recompleting bypass pay. IPC's gas production in the Suffield area is established and therefore infrastructure investment is expected to be minimal and commercial well recovery can be demonstrated. Sanction of these developments is sensitive to natural gas pricing. Project development timing for the highest ranked targets will potentially be within the next two to five years, with the remainder within the next ten years.

Key positive factors relevant to the contingent resource estimates for Suffield and Alderson shallow gas include:

- established recovery technology, including demonstration of commercial production rates in the subject reservoir;
- available facilities and infrastructure currently in place from the Corporation's existing operations in the subject areas; and
- ongoing and continual operational activity in the areas by the Corporation.

Key negative factors relevant to the contingent resource estimates for Suffield and Alderson shallow gas include:

- economic sensitivity to future gas pricing; and
- the limited economic value of shallow gas opportunities in the context of the Corporation's broader asset portfolio in the current commodity pricing environment.

These volumes are classed as Development on Hold. Two contingencies are identified for Suffield shallow gas contingent resource development:

Timing of Production and Development

The Corporation's lands in Suffield and Alderson are well defined and largely developed. The primary contingency for the shallow gas contingent resource locations is a lack of corporate commitment to developing the wells within the five year timeframe recommended by COGEH for reserves assignments.

Economic Viability

Based on offsetting well performance in these areas, it is likely that a portion of the shallow gas contingent resource opportunities will be economic and a portion will be sub-economic. Further review of operating costs, capital costs, royalties and incentives would need to be completed for this contingency to be lifted.

The contingent heavy oil resources in the Suffield area are attributed to development drilling. The development is expected to be phased and consists of drilling horizontal wells targeting Mannville and Detrital reservoirs. IPC's oil production in the Suffield area is established therefore infrastructure investment is expected to be minimal commercial well recovery can be demonstrated. Sanction of these developments is sensitive to oil pricing.

Key positive factors relevant to the contingent resource estimates for Suffield heavy oil include:

- established recovery technology, including widespread successful implementation in the subject reservoir;
- available facilities and infrastructure currently in place from the Corporation's existing operations in the subject area; and
- active and continual implementation of development drilling in the subject area by the Corporation.

Key negative factors relevant to the contingent resource estimates for development for Suffield heavy oil include:

- economic sensitivity to future oil pricing; and
- highly variable range of well productivity.

These volumes are classed as Development on Hold. Three contingencies are identified for Suffield heavy oil contingent resource development:

Evaluation Drilling

In the Detrital opportunities there is a requirement for more evaluation drilling to better establish commercial reservoir productivity. The Detrital has producing wells, though mapping of opportunities is largely seismic driven as it is not a continuous reservoir. As a result, additional drilling to establish commercial productivity within each Detrital pool is necessary to satisfy COGEH prerequisites for reserves assignment, at which time this contingency would be removed. The Mannville resources in the Falcon area will also require additional evaluation drilling before recoverable volumes can be classified as reserves due to limited wells and relatively poor existing production performance.

Timing of Production and Development

The Corporation's lands in the Mannville formation in the Suffield area are well delineated and largely developed. The primary contingency for the Mannville locations is a lack of corporate commitment to developing the wells within the five year timeframe.
Economic Viability

Based on offsetting well performance in these areas it is likely that a portion of the heavy oil contingent resource opportunities will be economic and a portion will be sub-economic. Further review of operating costs, capital costs, royalties and incentives would need to be completed for this contingency to be lifted.

Blackrod

The contingent bitumen resources outlined in this report are attributed to a thermal enhanced oil recovery project in the Blackrod area of Alberta. The overall development concept proposed by the Corporation is to develop the Blackrod leases in three separate phases. Phase 1 is being constructed as a 30,000 barrel per day development project; Phase 2 includes an expansion to a 50,000 barrel per day development project; and Phase 3 includes expansion to an 80,000 barrel per day development project. The below commentary and values are only applicable to the Phase 2 and 3 developments of the Blackrod area. Phase 1 volumes were upgraded to reserves as of December 31, 2022 and December 31, 2024, and are no longer included in this Schedule.

Key positive factors relevant to the contingent resource estimates for the Blackrod Phases 2 and 3 in situ oil sands projects include:

- established recovery technology, including a successful pilot in the subject reservoir;
- well defined development plan; and
- well delineated relatively homogeneous in-place-bitumen resource volume.

Key negative factors relevant to the contingent resource estimates for the Blackrod Phases 2 and 3 in situ oil sands projects include:

- economic sensitivity to future oil pricing;
- potential for government policy changes regarding carbon emissions to impact project viability;
- ability to access (in a timely and cost-effective fashion) the significant capital required to develop the resources;
- ability to procure services to develop resources at an appropriate cost;
- potential lack of available pipeline capacity; and
- market sensitivity to the number of competing oil projects potentially coming on-stream in a similar timeframe.

These volumes are classed as Development on Hold. Four contingencies are identified for the Blackrod Phases 2 and 3 project:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the implementation and operation of the SAGD recovery process. AER regulations generally require 8 delineation wells per section (or lower density delineation drilling combined with 3D seismic data) within the project area for Grand Rapids project applications. It is expected that the delineation well density and seismic data acquisition requirements for the majority of the project area will be met prior to commencement of development of Phases 2 and 3, at which time this contingency would be lifted.

Regulatory Approval

The absence of the submission of an application to expand the SAGD development beyond the Phase 1 project area. The Corporation received approval from the Alberta Energy Regulator and Alberta government in September 2016. An amendment to the development application was submitted and approved to reflect the revised Phase 1 capacity and planned development, taking into account modern technological advancements and optimized project scope. No application currently exists for the areas identified as Phases 2 and 3. In addition, changes in Alberta Government carbon emission policies could impede the approval of in situ oil sands projects in the future. It is expected that as the Corporation moves forward with Phase 1 (with completion of central facilities construction and first production) the Corporation will have sufficient information to move forward with expansion of the application area to a larger scale project, at which time this contingency would be removed.

Corporate Commitment

The absence of a final investment decision and endorsement from the Board of Directors of the Corporation to move forward with development of Phases 2 and 3 of the Blackrod assets. While the Corporation has consciously demonstrated a strong focus on its major assets and continues to actively work towards commercialization of the Blackrod project, it is acknowledged that Blackrod Phases 2 and 3 represent the largest project in the Corporation portfolio both in terms of capital requirements and resource base. It is likely that a final investment decision to approve Phases 2 and 3 will not occur for several years and as a result there is potential for delays or revisions to the development plan. It is anticipated that internal approvals to proceed are highly likely as Phase 1 commences and the Corporation moves towards expansion applications and final investment decisions for Phases 2 and 3, at which point this contingency would be lifted.

Timing of Production and Development

The timing of significant capital spending, production and development of Phases 2 and 3 is estimated to commence beyond the five year reasonable time periods recommended in COGEH for classification as proved and probable reserves. The large size of the resource base at Blackrod presents the need for a phased development plan executed over an extended time period to fully develop the resources. It is expected that as Phase 1 commences and the Corporation moves towards expansion applications and final investment decisions for Phases 2 and 3, the timing of significant capital spending, production and development will fall within the reasonable timeframes required for reserves classification, at which time this contingency would be removed.

Onion Lake Thermal

The thermal contingent heavy oil resources in the Onion Lake area of Saskatchewan are attributed to a thermal enhanced oil recovery project. Commercial production is demonstrated from earlier and ongoing phases and IPC has existing operational experience at this site. Sanction of this expansion is sensitive to oil pricing and potential regulatory changes that could be related to future First Nations leases.

Key positive factors relevant to the contingent resource estimates for the Onion Lake thermal project include:

- established recovery technology, including demonstration of commercial production rates in the subject reservoir;
- full regulatory approval received for the first and second phases of the project;
- well defined development plan; and
- existing fully operational central processing facility infrastructure in place.

Key negative factors relevant to the contingent resource estimate for the Onion Lake thermal project include:

- economic sensitivity to future oil pricing; and
- potential for IOGC to introduce policy changes for First Nations leases which could impact future lease agreements.

These volumes are classed as Development on Hold. Three contingencies are identified for the Onion Lake thermal contingent resource development:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the successful implementation and operation of the modified SAGD recovery process. Delineation through primary development drilling is currently ongoing and it is expected that the delineation necessary for adequate reservoir evaluation within the project area will be met prior to the first Phase Three well pad being drilled, at which time this contingency would be lifted.

Regulatory Approval

The Corporation’s lands in the Onion Lake area are leased from the Onion Lake Cree Nation (OLCN), are subject to Indian Oil and Gas Canada (IOGC) policies and approvals, as well as approvals from Saskatchewan Energy and Resources (SER). An application to expand the commercial modified SAGD development beyond the existing OLCN/OLE approved thermal EOR development area and facility capacities has not been submitted by the Corporation. It is expected that as the Corporation nears a final investment decision for developing additional acreage, OLCN/OLE agreements will be affirmed and further expansion applications will be submitted, at which point this contingency would be lifted. Within the thermal EOR development area is a sub-area where the Corporation has received regulatory approval for Phases One and Two of the Onion Lake thermal project from OLCN/OLE, SER and IOGC. Reserves were assigned to this area. Reserves were also assigned to the lands where the Corporation and OLCN/OLE have a thermal EOR development agreement in place that are outside of the existing SER/IOGC approval area based on the expectation that these lands will receive SER/IOGC approval as the Corporation expands the commercial project and submits an application to include this area. These reserves volumes have been excluded from the contingent resources volumes.

Timing of Production and Development

The timing of production and development is estimated to commence beyond reasonable time periods as described in COGEH as a requirement for classification as reserves. It is expected that as development planning continues, the timing of production and development will fall within the timeframes and certainty required for reserves classification, at which time this contingency would be lifted.

Mooney

The contingent heavy oil resource estimates in the Mooney area of Alberta are attributed to deploying a Polymer Enhanced Oil Recovery project to the existing development and areas immediately offsetting existing development. The development plan is well defined and the operating facility is in place. Sanction of this project is dependent on future oil and chemical prices and predicted flood performance in the reservoir. The Corporation includes reserve estimates for Phases One and Two of the Mooney project; the contingent resource estimates relate to the future potential development of Phases Three and Four.

Key positive factors relevant to the contingent resource estimate for Mooney Phases Three and Four include:

- established recovery technology, including successful implementation in the subject reservoir;
- regulatory approval obtained for Phases One and Two of the project;
- well defined development plan; and
- fully operational injection and production facility and surface infrastructure in place.

Key negative factors relevant to the contingent resource estimate for Mooney Phases Three and Four include:

- economics highly sensitive to future oil and chemical pricing;
- flood performance susceptible to reservoir heterogeneities; and
- comparatively limited resource base within the Corporation's broader asset portfolio.

These volumes are classed as Development on Hold. Four contingencies are identified for the Mooney Phases Three and Four contingent resources:

Evaluation Drilling

There is a requirement for more evaluation drilling to confirm the reservoir characteristics needed for the implementation and operation of the Polymer recovery process. Certain portions of the reservoir, specifically stepping out southwards and eastwards of current productive development, are not sufficiently delineated and reservoir properties such as oil viscosity, presence of free gas, and formation heterogeneities need to be further defined. It is anticipated that the reservoir characteristics pertinent to polymer flood performance will become better understood as the Corporation continues to delineate the reservoir with primary production wells, at which time this contingency would be lifted.

Regulatory Approval

There is a requirement for the submission of an application to expand the commercial EOR development beyond the Phase One and Two project areas. The Corporation has obtained regulatory approval for Phases One and Two of the Mooney project, but no expansion application currently exists for the Phases Three and Four contingent resource volumes.

Corporate Commitment

The final investment decision and endorsement from the Corporation to move forward with development of Phases Three and four has not been made. The Corporation has historically focused development efforts towards its other major assets. For year-end 2024 this focus is much the same. The Mooney property was shut in in 2020 and reactivated in 2021 due to challenging economics. Mooney Phases Three and Four represent some of the lowest materiality projects in the Corporation's portfolio in terms of resource base and expected value. It is likely that a final investment decision to approve these Phases Three and Four will not occur for several years, and as a result there is potential for delays or revisions to the development plan.

Timing of Production and Development

The timing of production and development of the flood patterns is estimated to commence beyond the five year time period deemed reasonable for classification as proved or probable reserves. The strategic goals of the Corporation in managing its asset portfolio result in the need for a phased development plan executed over an extended time period to fully develop the Mooney resources.

Ferguson

The contingent resources at the Ferguson field are a combination of oil and gas resources. The oil resources are attributed to development drilling, re fracturing of existing wells and the optimization of the field's gas flood. The gas resources are attributed to blowdown associated with the gas flood reservoir.

Key positive factors relevant to the contingent resource estimates for Ferguson include:

- established recovery technologies, including widespread successful implementation in the subject reservoir; and
- available facilities and infrastructure currently in place from the Companies existing operations in the subject area.

Key negative factors relevant to the contingent resource estimates for Ferguson include:

- economic sensitivity to future oil and gas pricing; and
- lack of commitment and internal approvals to actively pursue the identified development opportunities at this time.

These volumes are classed as Development Unclarified. One contingency is identified for Ferguson contingent resource development:

Corporate Commitment

The Corporation has not committed to proceeding with the development opportunities classified as contingent resources in the Ferguson area until it can further assess the opportunities, clarify the development plan and compare the identified opportunities to other Corporation investment opportunities.

SCHEDULE B – FORM 51-101 F2 (SPROULE)

Form 51-101 F2

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

To the Board of Directors of International Petroleum Corporation:

1. We have evaluated IPC Canada Ltd.'s (the "Company") reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

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

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 data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

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 December 31, 2024, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

			Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location Of Reserves (Country)	Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2024	Canada				
Total			Nil	5,296,936	Nil	5,296,936

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of IPC Canada Ltd. (As of December 31, 2024)".

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited

Calgary, Alberta

PROFESSIONAL ENGINEER MATT THOMAS ALBERTA ID 84860

Mar. 10, 2025
Matthew Thomas, P.Eng.
Team Lead, Engineering

Sproule Associates Limited
APEGA Permit Number 00417

Meghan Klein

Meghan Klein, P.Eng.
Senior Manager, Engineering
DATE: Mar. 10, 2025 **RM APEGA ID #:** 84981

SCHEDULE C – FORM 51-101 F2 (ERCE)

Form 51-101 F2

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

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

1. We have audited the Company's Reserves data and certain Contingent Resources data as at December 31, 2024. The Reserves data are estimates of Proved Reserves and Probable Reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs. The Contingent Resources are risked estimates of volume of Contingent Resources as at December 31, 2024.
2. The Reserves data and Contingent Resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves data and Contingent 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 and Contingent Resources data are free of material misstatement. An audit also includes assessing whether the Reserves data 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 audited for the year ended December 31, 2024, and identifies the respective portions thereof that we have audited and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of [Audit/Evaluation/Review] Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue in USD (Before Income Taxes, 10% Discount Rate)			
			Audited (USD)	Evaluated (USD)	Reviewed (USD)	Total (USD)
ERC Equipoise	December 31, 2024	France	174,076,463	0	0	174,076,463
ERC Equipoise	December 31, 2024	Malaysia	54,334,547	0	0	54,334,547
Total			228,411,010	0	0	228,411,010

6. The following tables set forth the risked volume of Contingent Resources included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the Contingent 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 Gross Working Interest Volume Oil (MMstb)
Contingent Resources, Development	ERC Equipoise Ltd	December 31, 2024	France	9.59
Unclarified/Development On Hold (2C)	ERC Equipoise Ltd	December 31, 2024	Malaysia	0.62

7. In our opinion, the Reserves data and Contingent 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 and Contingent 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 and Contingent 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, 30 January 2025

Rhod Phillips, MEng, SPEE
Principal Reservoir Engineer, ERCE

SCHEDULE D – FORM 51-101 F3

Form 51-101 F3

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.

Sproule Associates Ltd. and ERC Equipoise Ltd., independent qualified reserves auditors or evaluators, have, as applicable, audited, evaluated and reviewed the Corporation's reserves data and contingent resources data. The reports of the independent qualified reserves auditors and evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves and Sustainability Committee of the Board of Directors of the Corporation has

a. reviewed the Corporation's procedures for providing information to the independent qualified reserves auditors and evaluators;
b. met with the independent qualified reserves auditors and evaluators to determine whether any restrictions affected the ability of the independent qualified reserves auditors and evaluators to report without reservation; and
c. reviewed the reserves data and contingent resources data, as applicable, with management and the independent qualified reserves auditors and evaluators.

The Reserves and Sustainability 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 and Sustainability Committee, approved

a. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;
b. the filing of Forms 51-101F2, which are the reports of the independent qualified reserves auditors and evaluators on the reserves data and contingent resources data; and
c. the content and filing of this report.

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

"William Lundin"

William Lundin, President and Chief Executive Officer

"Nicki Duncan"

Nicki Duncan, Chief Operating Officer

"Emily Moore"

Emily Moore, Director

"Chris Bruijnzeels"

Chris Bruijnzeels, Director

Date: March 24, 2025

SCHEDULE E – AUDIT COMMITTEE MANDATE

Audit Committee Mandate

Ratified as of March 20, 2025

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.

Internal Controls

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.

Risk Management

The Audit Committee shall coordinate with the Reserves and Sustainability Committee (as it relates to ESG (environmental, social and governance), sustainability and climate-related risks) and with the Compensation Committee (as it relates to compensation-related risks) and review with management:

i) the effectiveness of the Company's procedures with respect to risk identification, assessment and management;
ii) the Company's major risk exposures;
iii) the steps management has taken to monitor and control such exposures; and
iv) the effect of relevant regulatory initiatives and trends.
v) The Audit Committee, with the assistance of management, shall periodically report to the Board on these matters in support of the Board's responsibility for the management of the principal risks associated with the Company's business and operations.

Hedging Strategy

The Audit Committee shall be responsible, on behalf of the Board, for approving the hedging strategy of the Company from time to time, including with respect to commodity price, foreign exchange and interest rate hedging, financial or physical, intended to manage, mitigate or eliminate risks relation to commodity price, foreign exchange and interest rate fluctuations. The Company shall report to the Audit Committee at each Audit Committee meeting regarding hedges placed under the approved hedging strategy. The Audit Committee shall regularly report to the Board on the approved hedging strategy and on hedges placed under such strategy.

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

C. Ashley Heppenstall
Director, Chair of the Board
London, England

William Lundin
Director, President and Chief Executive Officer
Coppet, Switzerland

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Donald K. Charter
Director
Toronto, Ontario, Canada

L.H. (Harry) Lundin
Director
Toronto, Ontario, Canada

Emily Moore
Director
Toronto, Ontario, Canada

Mike Nicholson
Director
Monaco

Deborah Starkman
Director
Toronto, Ontario, Canada

OFFICERS

Wiliam Lundin
President and Chief Executive Officer
Coppet, Switzerland

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

Nicki Duncan
Chief Operating Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel
Geneva, Switzerland

Rebecca Gordon
Senior Vice President Corporate Planning and Investor Relations
Geneva, Switzerland

Chris Hogue
Senior Vice President Canada
Calgary, Alberta, Canada

Ryan Adair
Vice President Asset Management and Corporate Planning Canada
Calgary, Alberta, Canada

Curtis White
Vice President Commercial Canada
Calgary, Alberta, Canada

MEDIA AND INVESTOR RELATIONS

Robert Eriksson
Stockholm, Sweden

CORPORATE OFFICE

Suite 2800, 1055 Dunsmuir Street
Vancouver, British Columbia V7X 1L2 Canada
Telephone: +1 604 689 7842
Website: www.international-petroleum.com

OPERATIONS OFFICE

5 Chemin de la Pallanterie
1222 Vésenaz, Switzerland
Telephone: +41 22 595 10 50
E-mail: info@international-petroleum.com

REGISTERED AND RECORDS OFFICE

Suite 3500, 1133 Melville Street
Vancouver, British Columbia V6E 4E5 Canada

INDEPENDENT AUDITORS

PricewaterhouseCoopers LLP, Canada

TRANSFER AGENT

Computershare Investor Services Inc.
Calgary, Alberta and Toronto, Ontario

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and Nasdaq Stockholm
Trading Symbol: IPCO

International
Petroleum
Corp.

International Petroleum Corporation
Suite 2800
1055 Dunsmuir Street
Vancouver, V7X 1L2
Canada
Tel. +1 604 689 7842
E-mail : info@international-petroleum.com
Web : www.international-petroleum.com

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