Q4

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2022

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Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, 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 this MD&A. See "Non-IFRS Measures" on page 23.

Forward-Looking Statements
Certain statements contained in this MD&A 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. 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". 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. For additional information underlying forward-looking statements, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 36.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (other than the assets to be acquired in the acquisition of Cor4) are effective as of December 31, 2022, 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, 2022, 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, 2022, 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, 2022, price forecasts.

Reserve estimates and estimates of future net revenue in respect of the oil and gas assets of Cor4 are effective as of December 31, 2022, and have been audited by a qualified reserves auditor (as defined in NI 51-101), in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022, price forecasts.

Certain abbreviations and technical terms used in this MD&A are defined or described under the heading "Other Supplementary Information".

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated February 7, 2023 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's audited consolidated financial statements and accompanying notes for the year ended December 31, 2022 ("Financial Statements").

Group Overview

The Group is in the business of 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.

The Corporation's common shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden. The Corporation is incorporated and domiciled in British Columbia, Canada, under the Business Corporations Act. The address of its registered office is Suite 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

Basis of Preparation

The MD&A and the Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Financial information is presented in United States Dollars ("USD"). However, as the Group operates in Europe and in Canada, certain financial information prepared by subsidiaries has been reported in Euros ("EUR") and in Canadian Dollars ("CAD"). In addition, certain costs relating to the operations in Malaysia, which are reported in USD, are incurred in Malaysian Ringgit ("MYR").

Exchange rates for the relevant currencies of the Group with respect to the US Dollar are as follows:

	December 31, 2022		December 31, 2021	
	Average	Period end	Average	Year end
1 EUR equals USD	1.0539	1.0666	1.1835	1.1326
1 USD equals CAD	1.3015	1.3538	1.2536	1.2708
1 USD equals MYR	4.3995	4.4050	4.1433	4.1660

HIGHLIGHTS

2022 Business Highlights

- Decision taken to advance the development of Phase 1 of the Blackrod project in Canada following the completion of front end engineering design (FEED) studies, maturing 218 million barrels of oil equivalent (MMboe) of 2P reserves.[1][2]
- In Q3 2022, published IPC's third annual Sustainability Report, aligned with the Global Reporting Initiative (GRI) standards and the Task Force on Climate-Related Financial Disclosures (TCFD).
- Expanding our stated commitment to reduce our net emissions intensity to 20 kg CO_2/boe by 2025, now expecting to remain at those levels through end 2027.
- 8.3 million common shares cancelled in early Q3 2022 following the successful conclusion of IPC's first Substantial Issuer Bid (SIB), returning MUSD 100 to shareholders.
- 9.5 million common shares purchased and cancelled from December 2021 to December 2022 under IPC's normal course issuer bid (NCIB) and a further 1.5 million common shares purchased for cancellation during December 2022 and January 2023 under the renewed NCIB.
- Successfully concluded material 2022 capital investment program of MUSD 163, increasing IPC's 2022 production.
- Average net production of approximately 49,200 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2022 was above the high end of the guidance range for the period (46% heavy crude oil, 21% light and medium crude oil and 33% natural gas).[1]
- Full year 2022 average net production was 48,600 boepd, above the high end of annual guidance and a record high for IPC.[1]
- Ten-year extension agreed for our Bertam Field, Malaysia production sharing contract (PSC) to 2035.

2022 Financial Highlights

- Operating costs per boe of USD 16.9 for the fourth quarter of 2022 and USD 16.6 for the full year in line with full year guidance of USD 16 to 17 per boe.[3]
- Strong operating cash flow (OCF) generation for the fourth quarter and full year 2022 amounted to MUSD 114 and MUSD 623, respectively.[3]
- Capital and decommissioning expenditures of MUSD 44 for the fourth quarter and MUSD 163 for the full year 2022, slightly below full year guidance of MUSD 170 with some carry over expenditure deferred into 2023.
- Strong free cash flow (FCF) generation for the fourth quarter and full year 2022 amounted to MUSD 65 and MUSD 430, respectively.[3]
- Net cash of MUSD 175 as at December 31, 2022, up from net debt of MUSD 94 as at December 31, 2021.[3]
- Net result of MUSD 61 for the fourth quarter of 2022 and MUSD 338 for the full year 2022.
- IPC's inaugural USD 300 million bond issued in Q1 2022.

Reserves, Resources and Value

- Total 2P reserves as at December 31, 2022 of 487 million boe (MMboe), representing a reserves replacement ratio of over 1,300% compared to year-end 2021, with a reserves life index (RLI) of 27 years.[1][2]
- Matured 218 MMboe into 2P reserves from contingent resources following decision to advance Phase 1 of the Blackrod project.
- Contingent resources (best estimate, unrisked) as at December 31, 2022 of 1,162 MMboe.[1][2]
- 2P reserves net asset value (NAV) as at December 31, 2022 of MUSD 3,545 (10% discount rate) to MUSD 4,184 (8% discount rate). [1][2][4][5]

2023 Annual Guidance

- Full year 2023 average net production forecast at 48,000 to 50,000 boepd.[1]
- Full year 2023 operating costs guidance forecast at USD 17.5 to 18 per boe.[3]
- Full year 2023 OCF guidance estimated at between MUSD 250 to 495 (assuming Brent USD 70 to 100 per barrel).[3]
- Full year 2023 capital and decommissioning expenditures guidance forecast at MUSD 365, including MUSD 287 relating to Phase 1 of the Blackrod project.
- Full year 2023 FCF ranges from approximately MUSD 140 to 390 (assuming Brent USD 70 to 100 per barrel) before taking into account proposed Blackrod capital expenditures, or MUSD -145 to 105 including proposed Blackrod capital expenditures. [3]

Business Plan Production and Cash Flow Guidance

- 2023 – 2027 business plan forecasts:
  - average net production forecast in excess of 50,000 boepd.(1)
  - capital expenditure forecast of USD 14 per boe, including USD 10 per boe for the Blackrod Phase 1 project.
  - operating costs forecast of USD 18 per boe.(3)
  - FCF forecast of approximately MUSD 700 to 1,400 (assuming Brent USD 75 to 95 per barrel).(3)(7)
- 2028 – 2032 business plan forecasts:
  - average net production forecast in excess of 65,000 boepd.(1)
  - capital expenditure forecast of USD 5 per boe.
  - operating costs forecast of USD 18 per boe.(3)
  - FCF forecast of approximately MUSD 1,900 to 3,000 (assuming Brent 75 to 95 USD per barrel).(3)(7)

	Three months ended December 31		Year ended December 31	
USD Thousands	2022	2021	2022	2021
Revenue	**256,479**	215,296	**1,135,958**	666,409
Gross profit	**95,411**	79,469	**516,709**	210,321
Net result	**61,183**	66,918	**337,725**	146,059
Operating cash flow(3)	**113,668**	110,687	**622,947**	336,732
Free cash flow(3)	**65,288**	86,960	**430,242**	262,884
EBITDA(3)	**125,651**	110,087	**639,480**	330,754
Net Cash / (Debt)(3)	**175,098**	(94,312)	**175,098**	(94,312)

OPERATIONS REVIEW

Business Overview

During 2022, oil and gas prices were much stronger compared to the full year 2021 average of USD 71 per barrel, with average Brent prices of USD 101 per barrel for the full year. Prices did retreat from second quarter highs in the second half as the tailwinds of tight supply and demand balances combined with very low inventory levels were more than offset by the headwinds of recessionary fears and the impact on future demand, Strategic Petroleum Reserve (SPR) releases in the United States and Covid-19 lockdowns in China.

In Canada, fourth quarter 2022 West Texas Intermediate (WTI) to Western Canadian Select (WCS) crude price differentials averaged around USD 26 per barrel, USD 6 per barrel wider than the third quarter of 2022. Forward markets into 2023 are pricing a tighter WTI/WCS differential at around USD 22 per barrel. Market commentators believe a return from US refinery outages as well as the end of the US SPR release program should provide more positive tailwinds for the WTI/WCS differential as we progress through 2023. IPC positioned itself well to mitigate this widening in the fourth quarter of 2022 with approximately two-thirds of our WTI/WCS differential exposure hedged at around USD 13 per barrel.

Gas markets remained relatively strong during the fourth quarter of 2022. IPC's average realised gas price was CAD 5.90 per Mcf, well above the average fourth quarter AECO benchmark price of CAD 5.00 per Mcf as IPC benefitted from higher Empress price differentials. Forward prices have softened recently trading at around CAD 3.10 per Mcf for the remainder of 2023. IPC has hedged AECO gas prices: 33.7 MMcf per day at CAD 6.26 per Mcf in Q1 2023 and at CAD 4.10 per Mcf from April to October 2023.

IPC benefits from a well balanced mix of production comprising approximately 50% Canadian Crude, 34% Canadian Natural Gas and 16% Brent weighted oil. With synchronized strength in pricing across the entire energy complex, combined with delivering operational excellence above the high end of our 2022 guidance, IPC has again been able to deliver a very strong financial performance in the fourth quarter and throughout the full year 2022.

Fourth Quarter and Full Year 2022 Highlights

During the fourth quarter of 2022, our assets delivered average net production of 49,200 boepd, above our high end guidance for the quarter. This was made possible by the very high uptime performance across all of our assets as well as the production contribution from our 2022 investment program in Malaysia and Canada. Full year 2022 average net production of 48,600 boepd was above the upper end of the guidance range of 48,000 boepd.(1)

Our operating costs per boe for the fourth quarter of 2022 was USD 16.9, in line with our latest guidance. Full year 2022 operating costs per boe was USD 16.6, in line with guidance of USD 16 to 17 per boe.(2)

Operating cash flow (OCF) generation for the fourth quarter of 2022 was USD 114 million. Full year 2022 OCF was USD 623 million in line with our lower end most recent guidance of USD 620 which assumed Brent USD 85 per barrel for November and December 2022.(2)

Capital and decommissioning expenditure for the fourth quarter of 2022 was USD 44 million. Full year 2022 capital and decommissioning expenditure of USD 163 million was marginally below guidance of USD 170 million with some carry over expenditure deferred into 2023.

Free cash flow (FCF) generation was strong at USD 65 million during the fourth quarter of 2022. Full year 2022 FCF generation was USD 430 million, in line with our most recent guidance of USD 425 to 460 million (assumed Brent USD 85 to 100 per barrel for November and December 2022) achieving a record high for the company. This represents approximately 29% of IPC's current market capitalization.(3)

During the fourth quarter of 2022, IPC's net cash position was further strengthened with a build to USD 175 million. Gross cash on the balance sheet amounts to USD 487 million providing a significant war chest to pursue our three strategic pillars of returning value to stakeholders, pursuing value adding M&A and maturing our contingent resource base into 2P reserves.(3)

Phase 1 Blackrod Project

Following the successful completion of FEED studies and the continued strong production performance from well pair three during 2022, IPC has taken the decision to advance the development of Phase 1 of the Blackrod project. Development capital expenditure to first oil is estimated at approximately USD 850 million (unrisked, including inflation and contingencies). First oil of the Phase 1 development is estimated to be in late 2026, with forecast production of 30,000 boepd by 2028. The breakeven oil price estimated by IPC assuming a 10% discount rate is a West Texas Intermediate (WTI) price of approximately USD 59 per barrel. Using the December 31, 2022 price forecasts of our qualified independent reserves evaluator, Sproule Associates Limited (Sproule), the net present value as at that date, at a 10% discount rate (after tax, unrisked), of Phase 1 of the Blackrod project is USD 807 million. IPC intends to fund the Phase 1 development with cash on hand and forecast FCF generated by its operations. (1)(2)(4)

M&A
IPC was pleased to announce on February 6, 2023 our fifth acquisition in five years. IPC has agreed to acquire 15.9 MMboe of 2P reserves adjacent to our Suffield property in Alberta, Canada, through the proposed acquisition of Cor4. This acquisition is forecast to add approximately 4,000 boepd to our Suffield area production in 2023 for an asset consideration of USD 62 million. The producing assets are complementary not only to our Suffield asset but in addition, to a recent land acquisition that IPC concluded in the fourth quarter of 2022. Following these acquisitions, we now have over 25 drilling inventory locations on the Ellerslie play fairway that extends from the west of our Suffield asset to our new land acquisition and into the Cor4 property. We plan to drill a total of six wells on this exciting new play in 2023. The Cor4 acquisition remains subject to regulatory approvals and is expected to complete by the end of Q1 2023. IPC intends to fund the consideration from existing cash on hand. (1)(2)

In total, IPC has added over USD 2.8 billion of value in FCF generation and 2P reserves NPV increases, from our last 4 acquisitions.(3)(4)

2022 and 2023 Capital Allocation Framework

Substantial Issuer Bid
During 2022, IPC was very pleased to have concluded our first substantial issuer bid (SIB) in line with our capital allocation framework. IPC returned USD 100 million to shareholders, with our remaining shareholders benefiting from the cancellation of the repurchased common shares, being approximately 5.5% of the total number of issued and outstanding shares. In early Q3 2022, IPC completed the repurchase of approximately 8.3 million common shares at CAD 15.50 (approximately SEK 122) per share under the SIB and the cancellation of these shares.

Normal Course Issuer Bid
During the period of December 2021 to December 2022, IPC purchased and cancelled an aggregate of approximately 9.5 million common shares under the normal course issuer bid / share repurchase program (NCIB). The average price of shares purchased under the NCIB during that period was SEK 83 / CAD 10.70 per share.

In Q4 2022, IPC announced the renewal of the NCIB, with the ability to repurchase up to approximately 9.3 million common shares over the twelve-month period to December 2023. IPC repurchased in December 2022 and subsequently cancelled approximately 730,000 common shares. By the end of January 2023, IPC repurchased for cancellation a further approximately 810,000 common shares. The average price of common shares purchased under the renewed NCIB during December 2022 and January 2023 was SEK 111 / CAD 14.50 per share.

As at February 7, 2023, IPC had a total of 136,089,756 common shares issued and outstanding, of which IPC holds 71,416 common shares in treasury.

2023 Capital Allocation Plans
IPC's capital allocation framework consists of distributing to shareholders a minimum of 40% of the FCF generated by IPC, provided that IPC's net debt to EBITDA ratio is at or below 1 time.(3) These shareholder distributions are planned to be implemented by continued share repurchases under the NCIB as well as the consideration by IPC of other forms of shareholder distributions, subject to further applicable regulatory and corporate approvals.

Despite the higher level of capital investment and lower FCF forecast during 2023, and notwithstanding the capital allocation framework described above, IPC plans to continue to purchase and cancel common shares under the NCIB to the remaining limit of 7.8 million common shares by the end of December 2023, resulting in the cancellation of 7% of shares outstanding as of December 2022. We believe a combination of materially growing our 2P reserves, production and asset value whilst reducing our share count is a winning combination for shareholders.(3)

Environmental, Social and Governance (ESG) Performance
Responsible operatorship and ensuring that we adhere to the highest principles of business conduct have been integral parts of how we do business since IPC started in 2017. Since that time, IPC has rapidly grown our business and we continue to further develop and improve our sustainability strategy. An important part of this journey involves the measurement and transparent reporting of a broad range of ESG metrics. With the publication of our second quarter 2022 financial report, we were very pleased to publish our third Sustainability Report, aligned with the Global Reporting Initiative standards and the Task Force on Climate-Related Financial Disclosures. As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of IPC's 2019 baseline and IPC remains on track to achieve this reduction. Furthermore, we are extending our commitment to remain at 2025 levels of 20 kg CO_2/boe through to the end of 2027.

During the fourth quarter of 2022 and for the full year 2022, IPC recorded no material safety or environmental incidents.

Reserves, Resources and Value

As at the end of December 2022, IPC's 2P reserves are 487 MMboe. During 2022, IPC replaced 13 times its annual production, mainly as a result of maturing 218 MMboe of 2P reserves from contingent resources related to Phase 1 of the Blackrod project and acquiring 15.9 MMboe in the acquisition of Cor4. The reserves life index (RLI) as at December 31, 2022, increases to approximately 27 years. [1][2]

The net present value (NPV) of IPC's 2P reserves as at December 31, 2022 was USD 3,432 million. IPC's net asset value (NAV) was USD 3,545 million or SEK 270 / CAD 35 per share as at December 31, 2022. To take into account the higher interest rate environment, IPC now presents 2P reserves NPV and NAV at a discount rate of 10%, compared to a discount rate of 8% in previous periods. At a discount rate of 8%, as at December 31, 2022, the NPV of IPC's 2P reserves as at December 31, 2022 was USD 4,071 million and the NAV was USD 4,184 million or SEK 319 / CAD 41 per share.[2][4][5]

In addition, IPC's best estimate contingent resources (unrisked) as at December 31, 2022 are 1,162 MMboe, of which over 1,000 MMboe relate to future potential phases of the Blackrod project.[1][2]

2023 Budget and Operational Guidance

We are pleased to announce our 2023 average net production guidance is 48,000 to 50,000 boepd, a 2,000 boepd increase from our original 2022 CMD guidance. We forecast operating costs for 2023 to be USD 17.5 to 18 per boe, with the forecast increase from 2022 mainly due to the reclassification of Blackrod operating costs.[1][3]

We also forecast significant FCF generation based on our 2P reserves base of an aggregate of more than USD 700 to 1,400 million over the period of 2023 to 2027. In addition, we forecast FCF generation of USD 1,900 to 3,000 million over the period of 2028 to 2032, assuming completion of Phase 1 of the Blackrod project.[2][3][7]

Our 2023 capital and decommissioning expenditure budget is USD 365 million, with over USD 287 million forecast for the Phase 1 development of the Blackrod project. The remainder of the 2023 budget includes the continued Pad L investment at Onion Lake Thermal, optimisation projects at Suffield gas, and continued development at the Ferguson asset in Canada. We plan further study work in Malaysia on the Bertam field and, in France, completion of the first phase of the Villeperdue West development project and a further sidetrack well.

IPC has decided to materially scale back capital expenditure on the base business from USD 163 million in 2022 to a forecast USD 78 million in 2023 including decommissioning expenditure. Limited investment in our current assets and the planned investments in the Cor4 assets to be acquired are forecast to provide production growth in the short to medium term, as we proceed with the Blackrod Phase 1 investment. Total base business capital expenditure inclusive of Cor4 acquisition price of USD 62 million amounts to USD 130 million, in line with the original 2022 capital expenditure budget and delivering a similar 2,000 boepd increase in production guidance year over year. IPC has significant flexibility to amend our business plans based on the development of commodity prices during 2023.

Further details regarding IPC's proposed 2023 budget and operational guidance will be provided at IPC's Capital Markets Day presentation to be held on February 7, 2023 at 14:00 CET. A copy of the Capital Markets Day presentation will be available on IPC's website at www.international-petroleum.com

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the material change report (MCR) available on IPC's website at www.international-petroleum.com and filed on the date of this MD&A under IPC's profile on SEDAR at www.sedar.com. Includes the 2P reserves as at December 31, 2022 and the forecast production, operating costs and capital expenditures attributable to the oil and gas assets of Cor4, assuming acquisition as of such date. Completion of the Cor4 transaction remains subject to regulatory approvals and is expected to complete by the end of Q1 2023.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's and Cor4's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of NPV, are further described in the MCR. 2P reserves as at December 31, 2022 of 487 MMboe includes 471 MMboe attributable to IPC's oil and gas assets and 15.9 MMboe attributable to Cor4's oil and gas assets. Reserves replacement ratio is based on 2P reserves of 270 MMboe as at December 31, 2021, sales production during 2022 of 16.9 MMboe, additions to 2P reserves during 2022 of 218 MMboe (or 234 MMboe including the 2P reserves attributable to the acquisition of Cor4) and 2P reserves of 471 MMboe (or 487 MMboe including the 2P reserves attributable to the acquisition of Cor4) as at December 31, 2022.

(3) Non-IFRS measure, see "Non-IFRS Measures" below and in the MD&A.

(4) NPV is after tax, discounted at 10% and based upon the forecast prices and other assumptions further described in the MCR. NPV of the 2P reserves as at December 31, 2022 of USD 3,432 million includes USD 3,279 million attributable to IPC's oil and gas assets and USD 153 million attributable to Cor4's oil and gas assets. See "Reserves and Resources Advisory" below.

(5) NAV is calculated as NPV plus net cash of USD 175 million as at December 31, 2022 less the Cor4 acquisition consideration of USD 62 million.

(6) NAV per share is based on 136,827,999 IPC common shares outstanding as at December 31, 2022. NAV per share is not predictive and may not be reflective of current or future market prices for IPC common shares.

(7) Estimated FCF generation is based on IPC's current business plans over the periods of 2023 to 2027 and 2028 to 2032, including net cash of USD 175 million as at December 31, 2022 less the Cor4 acquisition consideration of USD 62 million. Assumptions include average net production of approximately 50 Mboepd over the period of 2023 to 2027, average net production of approximately 65 Mboepd over the period of 2028 to 2032, average Brent oil prices of USD 75 to 95 per boe escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the MCR. Free cash flow yield is based on IPC's market capitalization at close January 31, 2023 (112.5 SEK/share, 10.46 SEK/USD, USD 1,463 million). IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts. See "Cautionary Statement Regarding Forward-Looking Information" below.

Operations Overview

2022 Overview
IPC set a balanced capital budget for 2022, targeting production developments across all regions whilst having a continued focus on free cash flow delivery to the business. At the end of Q2 2022, on the back of strong operational performance and improved market conditions, IPC increased its capital expenditure forecast to allow for further conventional oil well drilling, natural gas recompletion activity and facility capacity optimisation in Canada.

From a development perspective, 2022 was an active year for IPC with new production well drilling and optimisation activity in all our operating regions. In Canada, drilling of the next sustaining production Pad L at Onion Lake Thermal is complete with facility works and tie ins scheduled for execution through 2023. The first phase of the Ferguson field development has been successfully executed with a total of 16 new oil wells more than doubling production at the asset. Conventional and EOR well drilling at the Suffield asset has been supplemented by gas recompletion and optimisation activity which continues to offset historical field declines. In Malaysia the A15 side-track production well and the planned three production well pump upgrades were successfully brought online during Q2 2022. In France, the three well drilling programme Villeperdue West commenced in Q4 2022 with production from all three wells expected through Q1 2023.

Reserves and Resources
The 2P reserves attributable to IPC's oil and gas assets are 487 MMboe as at December 31, 2022, with over 96% certified by independent third party reserve auditors (15.9 MMboe related to the Cor4 acquisition certified by an internal qualified reserves auditor). The reserve life index (RLI) as at December 31, 2022, is approximately 27 years. Best estimate contingent resources as at December 31, 2022, are 1,162 MMboe (unrisked). See "Reserves and Resources Advisory" below.

Production
The average net production during the fourth quarter of 2022 was in excess of 49,200 boepd. This is our fourth quarter in succession of delivering production above our high end CMD guidance. Exceptional operational performance and high production uptimes have been supplemented by the production benefit from the recent development investments in Canada and Malaysia. In Canada, optimisation activity at our Suffield assets continues to deliver strong results and for the fourth quarter in succession Onion Lake Thermal delivered record production. In addition, strong performance from the Malaysian and French assets continued in Q4 2022 with excellent operational uptime at the Bertam field in Malaysia and stable production in France.

With the exceptional operational delivery through 2022, IPC exits the year with a net average production of 48,600 boepd, 600 boepd above both our original high end guidance and the latest Q3 guidance of greater than 48,000 boepd.

The production during Q4 2022 with comparatives is summarized below:

Production in Mboepd	Three months ended December 31		Year ended December 31	
	2022	2021	**2022**	2021
Crude oil				
Canada – Northern Assets	16.0	14.2	15.6	12.8
Canada – Southern Assets	9.0	8.5	8.7	8.6
Malaysia	5.2	4.5	5.3	4.4
France	2.7	2.9	2.7	3.0
Total crude oil production	**32.9**	30.1	**32.3**	28.8
Gas				
Canada – Northern Assets	0.1	0.1	0.1	0.1
Canada – Southern Assets	16.2	16.6	16.2	16.6
Total gas production	**16.3**	16.7	**16.3**	16.7
Total production	**49.2**	46.8	**48.6**	45.5
Quantity in MMboe	**4.53**	4.31	**17.74**	16.61

See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory".

CANADA

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2022	2021	**2022**	2021
- Oil Onion Lake Thermal	100%	13.1	11.5	12.7	10.6
- Oil Suffield	100%	6.7	7.5	7.1	7.5
- Oil Ferguson	100%	2.3	1.0	1.6	1.1
- Oil Other	50-100%	2.9	2.7	2.9	2.2
- Gas	99.7%[1]	16.3	16.7	16.3	16.7
Canada		**41.3**	39.4	**40.6**	38.1

[1] *On a well count basis*

Production
Net production from IPC's Canadian assets during Q4 2022 was ahead of the latest guidance at 41,300 boepd despite earlier than forecast extreme cold weather conditions in the region. Recompletion and optimisation activity at the Suffield property continues to deliver strong results and offset field decline rates. For the fourth quarter in succession, Onion Lake Thermal delivered record production with strong base well performance and high production uptime.

Organic Growth and Capital Projects
At Onion Lake Thermal, the two new production infill wells have been brought online with strong initial performance supporting record production levels from the asset. At the end of Q4 2022, drilling of the next sustaining production Pad L has been completed with facility works and tie ins scheduled for execution through 2023.

At Ferguson, IPC successfully delivered the first phase of the planned field development, including sixteen new horizontal producers and a gas processing system capacity increase as part of the programme.

At Suffield Oil, as of the end of Q4 2022, two ASP injection and two production wells have been drilled as part of a planned expansion of the N2N EOR field. A further two conventional production and two water disposal wells were completed in Q4 with well clean up and performance testing ongoing.

By the end of Q4 at Suffield Gas, a total of 117 gas well recompletions have been executed and brought onstream.

Strong performance from the third well pair pilot project at the Blackrod asset continued through Q4 2022. Heat conformance and production performance remain ahead of expectation. As of the end of Q4 2022, Blackrod Phase 1 commercial development FEED studies have been completed in line with schedule.

MALAYSIA

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2022	2021	**2022**	2021
Bertam	100% [1]	**5.2**	4.5	**5.3**	4.4

[1] *100% from April 10, 2021 (75% previously)*

Production
Net production from the Bertam field on Block PM307 during Q4 2022 was stable and in line with the latest guidance at 5,200 boepd.

Organic Growth and Capital Projects
In Malaysia, the new A15 side-track production well and the planned three production well pump upgrades were successfully brought online during Q2 2022. In December 2022, IPC announced the agreement to extend the Bertam Field PSC by ten years to August 2035.

FRANCE

Production in Mboepd	WI	Three months ended December 31		Year ended December 31	
		2022	2021	**2022**	2021
France					
- Paris Basin	100%[1]	2.3	2.5	2.4	2.6
- Aquitaine	50%	0.4	0.4	0.3	0.4
		2.7	2.9	**2.7**	3.0

[1] *Except for the working interest in the Dommartin Lettree field of 43%*

Production
Net production in France during Q4 2022 was in line with the latest guidance at 2,700 boepd with stable production and high uptimes at the major producing fields.

Organic Growth
In France, IPC sanctioned a three horizontal well development at Villeperdue West as part of the capital expenditure plans for 2022. IPC continues to mature future development projects in France, with focus towards the undeveloped resource base within the Paris Basin.

In Q4 2022, the three well drilling programme Villeperdue West commenced with production from all three wells expected in Q1 2023.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	2022	2021	2020
Revenue	**1,135,958**	666,409	324,164
Gross profit	**516,709**	210,321	(83,986)
Net result	**337,725**	146,059	(77,941)
Earnings per share – USD	**2.30**	0.94	(0.50)
Earnings per share fully diluted – USD	**2.25**	0.92	(0.49)
Operating cash flow[1]	**622,947**	336,732	119,423
Free cash flow[1]	**430,242**	262,884	9,342
EBITDA[1]	**639,480**	330,754	108,451
Net cash / (debt) at period end[1]	**175,098**	(94,312)	(321,193)

[1] *See definition on page 23 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2022	December 31, 2021	December 31, 2020
Non-current assets	1,041,051	1,122,514	1,240,653
Current assets	638,566	151,160	92,467
Total assets	**1,679,617**	1,273,674	1,333,120
Total non-current liabilities	564,381	331,152	527,530
Current liabilities	149,905	94,979	97,137
Total liabilities	**714,286**	426,131	624,667
Net assets	**965,331**	847,543	708,453
Working capital (including cash)	**488,661**	56,181	(4,670)

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2022	Q4-22	Q3-22	Q2-22	Q1-22	2021	Q4-21	Q3-21	Q2-21	Q1-21
Revenue	**1,135,958**	**256,479**	300,770	317,403	261,306	**666,409**	215,296	172,551	144,278	134,284
Gross profit	**516,709**	**95,411**	140,489	161,709	119,100	**210,321**	79,469	58,636	34,286	37,930
Net result	**337,725**	**61,183**	90,503	105,217	80,822	**146,059**	66,918	30,557	21,693	26,891
Earnings per share – USD	**2.30**	**0.45**	0.63	0.70	0.52	**0.94**	0.43	0.20	0.14	0.17
Earnings per share fully diluted – USD	**2.25**	**0.44**	0.62	0.68	0.51	**0.92**	0.42	0.19	0.14	0.17
Operating cash flow[1]	**622,947**	**113,668**	171,654	192,515	145,110	**336,732**	110,687	91,365	66,959	67,721
Free cash flow[1]	**430,242**	**65,288**	116,681	151,792	96,479	**262,884**	86,960	76,607	50,366	48,951
EBITDA[1]	**639,480**	**125,651**	174,328	194,038	145,463	**330,754**	110,087	89,223	65,181	66,263
Net cash / (debt) at period end[1]	**175,098**	**175,098**	88,615	14,382	(42,367)	**(94,312)**	(94,312)	(161,199)	(240,617)	(286,132)

[1] *See definition on page 23 under "Non-IFRS measures"*

Selected Interim Financial Information

The Group operates within several geographical areas. Operating segments are reported at a country level, with Canada being further analyzed by main areas: (i) Canada – Northern Assets (comprising mainly of the Onion Lake Thermal asset) and (ii) Canada – Southern Assets (comprising of the Suffield assets and the Ferguson asset). This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – December 31, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	101,127	52,721	44,361	29,095	–	**227,304**
NGLs	–	142	–	–	–	**142**
Gas	256	35,656	–	–	–	**35,912**
Net sales of oil and gas	**101,383**	**88,519**	**44,361**	**29,095**	–	**263,358**
Change in under/over lift position	–	–	–	(7,642)	–	**(7,642)**
Royalties	(10,006)	(8,989)	–	–	–	**(18,995)**
Hedging settlement	12,308	7,277	–	–	–	**19,585**
Other operating revenue	–	–	–	173	–	**173**
Revenue	**103,685**	**86,807**	**44,361**	**21,626**	–	**256,479**
Operating costs	(23,247)	(32,964)	(9,394)	(10,764)	–	**(76,369)**
Cost of blending	(39,494)	(7,040)	–	–	–	**(46,534)**
Change in inventory position	(551)	124	(4,111)	(54)	–	**(4,592)**
Depletion and decommissioning costs	(8,256)	(10,591)	(8,667)	(2,806)	–	**(30,320)**
Depreciation of other assets	–	–	(2,695)	–	–	**(2,695)**
Exploration and business development costs	–	–	–	–	(558)	**(558)**
Gross profit/(loss)	**32,137**	**36,336**	**19,494**	**8,002**	**(558)**	**95,411**

	Three months ended – December 31, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	84,039	53,940	47,166	18,863	–	204,008
NGLs	–	172	–	–	–	172
Gas	212	33,076	–	–	–	33,288
Net sales of oil and gas	84,251	87,188	47,166	18,863	–	237,468
Change in under/over lift position	–	–	–	2,958	–	2,958
Royalties	(7,968)	(7,095)	–	–	–	(15,063)
Hedging settlement	(7,109)	(3,323)	–	–	–	(10,432)
Other operating revenue	–	171	–	194	–	365
Revenue	69,174	76,941	47,166	22,015	–	215,296
Operating costs	(20,956)	(27,412)	(5,964)	(10,610)	–	(64,942)
Cost of blending	(15,439)	(6,884)	–	–	–	(22,323)
Change in inventory position	(190)	(702)	(14,020)	(384)	–	(15,296)
Depletion and decommissioning costs	(8,121)	(10,758)	(7,843)	(3,571)	–	(30,293)
Depreciation of other assets	–	–	(2,628)	–	–	(2,628)
Exploration and business development costs	(4)	–	–	–	(341)	(345)
Gross profit/(loss)	24,464	31,185	16,711	7,450	(341)	79,469

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
	Year ended – December 31, 2022					
Crude oil	513,349	265,016	184,143	112,379	–	**1,074,887**
NGLs	–	774	–	–	–	**774**
Gas	1,082	153,672	–	–	–	**154,754**
Net sales of oil and gas	**514,431**	**419,462**	**184,143**	**112,379**	–	**1,230,415**
Change in under/over lift position	–	–	–	(8,553)	–	**(8,553)**
Royalties	(59,353)	(46,503)	–	–	–	**(105,856)**
Hedging settlement	18,842	283	–	–	–	**19,125**
Other operating revenue	–	111	–	716	–	**827**
Revenue	**473,920**	**373,353**	**184,143**	**104,542**	–	**1,135,958**
Operating costs	(101,443)	(115,574)	(35,051)	(42,248)	–	**(294,316)**
Cost of blending	(155,375)	(33,797)	–	–	–	**(189,172)**
Change in inventory position	721	317	(1,916)	720	–	**(158)**
Depletion and decommissioning costs	(33,097)	(41,980)	(34,687)	(12,277)	–	**(122,041)**
Depreciation of other tangible fixed assets	–	–	(10,787)	–	–	**(10,787)**
Exploration and business development costs	97	–	–	–	(2,872)	**(2,775)**
Gross profit/(loss)	**184,823**	**182,319**	**101,702**	**50,737**	**(2,872)**	**516,709**

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
	Year ended – December 31, 2021					
Crude oil	268,403	190,287	100,436	75,949	–	635,075
NGLs	–	570	–	–	–	570
Gas	630	99,389	–	–	–	100,019
Net sales of oil and gas	269,033	290,246	100,436	75,949	–	735,664
Change in under/over lift position	–	–	–	5,391	–	5,391
Royalties	(25,179)	(21,245)	–	–	–	(46,424)
Hedging settlement	(22,272)	(11,320)	–	–	–	(33,592)
Other operating revenue	–	171	4,208	927	64	5,370
Revenue	221,582	257,852	104,644	82,267	64	666,409
Operating costs	(79,213)	(102,084)	(27,080)	(39,852)	–	(248,229)
Cost of blending	(52,855)	(25,579)	–	–	–	(78,434)
Change in inventory position	368	(353)	1,837	(196)	–	1,656
Depletion and decommissioning costs	(29,667)	(43,097)	(30,156)	(16,093)	–	(119,013)
Depreciation of other tangible fixed assets	–	–	(10,108)	–	–	(10,108)
Exploration and business development costs	(8)	–	(259)	(7)	(1,686)	(1,960)
Gross profit/(loss)	60,207	86,739	38,878	26,119	(1,622)	210,321

Three months and year ended December 31, 2022, Review

Revenue
Total revenue amounted to USD 256,479 thousand for Q4 2022, compared to USD 215,296 thousand for Q4 2021 and USD 1,135,958 thousand for the year ended December 31, 2022 compared to USD 666,409 thousand for the year ended December 31, 2021 and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	**2022**	2021	**2022**	2021
Crude oil sales	227,304	204,008	1,074,887	635,075
Gas and NGL sales	36,054	33,460	155,528	100,589
Change in under/overlift position	(7,642)	2,958	(8,553)	5,391
Royalties	(18,995)	(15,063)	(105,856)	(46,424)
Hedging settlement	19,585	(10,432)	19,125	(33,592)
Other operating revenue	173	365	827	5,370
Total revenue	**256,479**	215,296	**1,135,958**	666,409

The main components of total revenue for the three and year ended December 31, 2022, and December 31, 2021, respectively, are detailed below.

Crude oil sales

	Three months ended – December 31, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	101,127	52,721	44,361	29,095	**227,304**
- Quantity sold in bbls	1,824,392	900,832	473,071	330,014	**3,528,309**
- Average price realized USD per bbl	55.43	58.52	93.77	88.16	**64.42**

	Three months ended – December 31, 2021				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	84,039	53,940	47,166	18,863	204,008
- Quantity sold in bbls	1,405,654	873,890	577,258	235,921	3,092,723
- Average price realized USD per bbl	59.79	61.72	81.71	79.96	65.96

Crude oil revenue was 11% higher in Q4 2022 compared to Q4 2021 mainly due to a higher volume sold as a result of increased production and more volume blended at Onion Lake following the commissioning of a pipeline in April 2022. Brent oil prices were higher in Q4 2022 versus Q4 2021, however the differential on Canadian pricing was higher in Q4 2022 compared to Q4 2021.

The Suffield area assets and Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q4 2022, WTI averaged USD 83 per bbl compared to USD 77 per bbl for Q4 2021 and the average discount to WCS used in our pricing formula was USD 26 per bbl compared to USD 15 per bbl for Q4 2021.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There were two cargo liftings in Malaysia during Q4 2022 in November and December and two cargo liftings in Q4 2021. Produced unsold oil barrels from Bertam at the end of Q4 2022 amounted to 93,000 barrels, see Change in Inventory Position section below. There was one Aquitaine cargo in France lifted in Q4 2022 compared to none in Q4 2021. The average Dated Brent crude oil price was USD 89 per bbl for Q4 2022 compared to USD 80 per bbl for the comparative period.

USD Thousands	Year ended – December 31, 2022				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	513,349	265,016	184,143	112,379	**1,074,887**
- Quantity sold in bbls	6,880,263	3,492,721	1,646,301	1,143,130	**13,162,415**
- Average price realized USD per bbl	74.61	75.88	111.85	98.31	**81.66**

USD Thousands	Year ended – December 31, 2021				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	268,403	190,287	100,436	75,949	635,075
- Quantity sold in bbls	5,118,726	3,505,698	1,337,346	1,069,276	11,031,046
- Average price realized USD per bbl	52.44	54.28	75.10	71.03	57.57

Crude oil revenue was 70% higher during the year ended December 31, 2022 compared to the year ended December 31, 2021 mainly due to the increase in achieved oil prices resulting from the improvement in market conditions, increased production and a greater volume of blended oil sold.

The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). WTI averaged USD 94 per bbl and the average discount from WTI to WCS was approximately USD 18 per bbl for the year ended December 31, 2022, compared to an average WTI of USD 68 per bbl and an average discount from WTI to WCS of USD 13 per bbl for the comparative period in 2021.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 101 per bbl for the year ended December 31, 2022 compared to USD 71 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – December 31, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	35,798	256	**36,054**
- Quantity sold in Mcf	8,256,010	70,093	**8,326,103**
- Average price realized USD per Mcf	4.34	3.65	**4.33**

	Three months ended – December 31, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	33,248	212	33,460
- Quantity sold in Mcf	8,536,894	69,643	8,606,537
- Average price realized USD per Mcf	3.89	3.05	3.89

Gas and NGL sales revenue was 8% higher for Q4 2022 compared to Q4 2021 mainly due to the higher achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q4 2022, IPC realized an average price of CAD 5.90 per Mcf compared to AECO average pricing of CAD 5.03 per Mcf.

	Year ended – December 31, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	154,446	1,082	**155,528**
- Quantity sold in Mcf	32,699,017	264,673	**32,963,690**
- Average price realized USD per Mcf	4.72	4.09	**4.72**

	Year ended – December 31, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	99,959	630	100,589
- Quantity sold in Mcf	33,731,280	237,489	33,968,769
- Average price realized USD per Mcf	2.96	2.65	2.96

Gas and NGL sales revenue was 55% higher for the year ended December 31, 2022 compared to the year ended December 31, 2021 mainly due to the higher achieved gas price. For the year ended December 31, 2022, IPC realized an average price of CAD 6.14 per Mcf compared to AECO average pricing of CAD 5.23 per Mcf.

Hedging settlement

IPC enters into risk management contracts in order to ensure a certain level of cash flow. It focuses mainly on oil price swaps and collars to limit pricing exposure. The oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlement for the year ended December 31, 2022 amounted to a gain of USD 19,125 thousand and consisted of a gain of USD 29,339 thousand on the oil contracts and a loss of USD 10,214 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue

Other operating revenue amounted to USD 173 thousand for Q4 2022 compared to USD 365 thousand for Q4 2021 and USD 827 thousand for the year ended December 31, 2022 compared to USD 5,370 thousand for the comparative period. Other operating revenue mainly consists of tariff income and fees for strategic storage of inventory in France. A significant part of other operating revenue in 2021 related to third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia until April 10, 2021. Following the withdrawal of Petronas Carigali Sdn Bhd from the Production Sharing Contract for the Bertam Field, and its interest being assigned to IPC, there is no such third party lease fee income after April 10, 2021. From this date, 100% of the lease income is eliminated from other operating revenue and the corresponding self-to-self lease fee is eliminated from operating costs, and IPC reports additional oil sales revenues associated with the assigned 25% working interest in the Bertam field.

Production costs

Production costs including inventory movements amounted to USD 127,495 thousand for Q4 2022 compared to USD 102,561 thousand for Q4 2021 and USD 483,646 thousand for the year ended December 31, 2022 compared to USD 325,007 thousand for the comparative period, and is analyzed as follows:

	Three months ended – December 31, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	32,964	23,247	13,534	10,764	(4,140)	**76,369**
USD/boe[2]	14.21	15.72	28.12	43.05	n/a	**16.86**
Cost of blending	7,040	39,494	–	–	–	**46,534**
Change in inventory position	(124)	551	4,111	54	–	**4,592**
Production costs	**39,880**	**63,292**	**17,645**	**10,818**	**(4,140)**	**127,495**

	Three months ended – December 31, 2021					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	27,412	20,956	10,104	10,610	(4,140)	64,942
USD/boe[2]	11.89	15.90	24.27	39.37	n/a	15.07
Cost of blending	6,884	15,439	–	–	–	22,323
Change in inventory position	702	190	14,020	384	–	15,296
Production costs	34,998	36,585	24,124	10,994	(4,140)	102,561

	Year ended – December 31, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	115,574	101,443	51,476	42,248	(16,425)	**294,316**
USD/boe[2]	12.71	17.75	26.72	41.75	n/a	**16.59**
Cost of blending	33,797	155,375	–	–	–	**189,172**
Change in inventory position	(317)	(721)	1,916	(720)	–	**158**
Production costs	**149,054**	**256,097**	**53,392**	**41,528**	**(16,425)**	**483,646**

	Year ended – December 31, 2021					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	102,084	79,213	51,420	39,852	(24,340)	248,229
USD/boe[2]	11.11	16.74	32.13	36.57	n/a	14.95
Cost of blending	25,579	52,855	–	–	–	78,434
Change in inventory position	353	(368)	(1,837)	196	–	(1,656)
Production costs	128,016	131,700	49,583	40,048	(24,340)	325,007

[1] *See definition on page 23 under "Non-IFRS measures".*
[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*
[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating costs per boe for Malaysia to USD 19.52 and USD 14.33 for Q4 2022 and Q4 2021 respectively and USD 18.20 and USD 16.92 for the year ended December 31, 2022, and December 31, 2021, respectively.*

Operating costs
Operating costs amounted to USD 76,369 thousand for Q4 2022 compared to USD 64,942 thousand for Q4 2021 and USD 294,316 thousand for the year ended December 31, 2022 compared to USD 248,229 for the year ended December 31, 2021. The increase in costs in Q4 2022 compared to Q4 2021 is due to higher energy prices, higher chemical costs and increased activity. Operating costs per boe amounted to USD 16.86 per boe in Q4 2022 compared with USD 15.07 per boe in Q4 2021 and was in line with the latest guidance for Q4 2022. Operating costs for the year ended December 31, 2022 amount to USD 16.59 per boe which was within the full year operating cost guidance of between USD 16 and 17 per boe.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. As a result of the blending, actual sales volumes are higher than produced barrels and the realized sales price of a blended barrel is higher than an unblended barrel. The majority of Onion Lake oil production is also blended and exported by pipeline since April 2022 with the commissioning of a third party export pipeline from the Onion Lake field to the gathering system.

The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 46,534 thousand for Q4 2022 compared to USD 22,323 thousand for Q4 2021 and USD 189,172 thousand for the year ended December 31, 2022 compared to USD 78,434 for the comparative period. The increase versus the comparative period is attributable to larger Onion Lake blending volumes and higher diluent prices in line with higher oil prices.

Change in inventory position

The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion, and market value, and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q4 2022, IPC had crude entitlement of 93,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold). Two crude cargo were lifted from Bertam in November and December 2022 with the next lifting expected in February 2023.

Depletion and decommissioning costs

The total depletion of oil and gas properties amounted to USD 30,320 thousand for Q4 2022 compared to USD 30,453 thousand for Q4 2021 and USD 122,041 thousand for the year ended December 31, 2022 compared to USD 119,013 thousand for the year ended December 31, 2021. The depletion charge is analyzed in the following tables:

	Three months ended – December 31, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,591	8,256	8,667	2,806	**30,320**
USD per boe	4.57	5.58	18.01	11.22	**6.69**

	Three months ended – December 31, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,758	8,121	7,843	3,571	30,293
USD per boe	4.67	6.16	18.84	13.25	7.03

	Year ended – December 31, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	41,980	33,097	34,687	12,277	**122,041**
USD per boe	4.62	5.79	18.01	12.13	**6.88**

	Year ended – December 31, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	43,097	29,667	30,156	16,093	119,013
USD per boe	4.69	6.27	18.84	14.77	7.17

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field.

Depreciation of other tangible fixed assets

The total depreciation of other assets amounted to USD 2,695 thousand for Q4 2022 compared to USD 2,628 thousand for Q4 2021 and USD 10,787 thousand for the year ended December 31, 2022 compared to USD 10,108 thousand for the year ended December 31, 2021. This relates to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis based on the Bertam field 2P reserves to August 2025 based on the original PSC expiry date.

Exploration and business development costs

The total exploration and business developments costs amounted to USD 558 thousand for Q4 2022 and USD 2,775 thousand for the year ended December 31, 2022. These costs mainly related to business development costs.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 14,440 thousand for the year ended December 31, 2022 compared to USD 12,364 thousand for the year ended December 31, 2021.

Net financial items
Net financial items amounted to a charge of USD 37,131 thousand for the year ended December 31, 2022, compared to a charge of USD 30,214 thousand for the year ended December 31, 2021, and included a largely non-cash net foreign exchange loss of USD 7,872 thousand for 2022 compared to a net foreign exchange loss of USD 1,994 thousand for 2021. The foreign exchange movements during the year ended December 31, 2022 are mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 29,259 thousand for the year ended December 31, 2022, compared to a charge of USD 28,220 thousand for the year ended December 31, 2021.

The interest expense amounted to USD 20,689 thousand for the year ended December 31, 2022, compared to USD 12,867 thousand for the comparative period in 2021. Despite the repayment of the outstanding reserve-based lending (RBL) credit facilities in February 2022, the cost of financing was higher during 2022 than the comparative period as a result of the interest paid and accrued at 7.25% per annum on the USD 300 million Bonds issued. Interest income generated on cash balances held in 2022 amounted to USD 6,966 thousand.

Following the repayment of the outstanding RBL credit facilities with a portion of the Bonds proceeds, the remaining capitalized RBL loan fees were fully expensed during Q1 2022. These expensed loan fees relating to the credit facilities and the amortization of the capitalised Bonds fees amounted to USD 3,252 thousand for the year ended December 31, 2022 compared to USD 2,068 thousand for the comparative period in 2021.

The unwinding of the asset retirement obligation discount rate amounted to USD 10,758 thousand for the year ended December 31, 2022, compared to USD 11,488 thousand for the year ended December 31, 2021.

Income tax
The corporate income tax amounted to a charge of USD 127,413 thousand for the year ended December 31, 2022, compared to a charge of USD 21,684 thousand for the year ended December 31, 2021 and included deferred taxes of USD 98,048 thousand and USD 17,104 thousand respectively.

Current income payable amounted to USD 29,365 thousand in 2022 and mainly related to France and Malaysia. No corporate income tax was payable in Canada in respect of 2022 due to the usage of historical tax pools. On September 30, 2022, the Council of the European Union ("EU") agreed to impose an EU-wide windfall profits tax on energy companies deriving income from operations in EU countries ("Solidarity Contribution"). The current tax in 2022 includes a Solidarity Contribution relating to the income in France amounting to USD 10,915 thousand which is payable in Q2 2023.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the the year ended December 31, 2022, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	69,196	49,566	27,305	12,244	**158,311**
Exploration and evaluation	–	(802)	149	4	**(649)**
	69,196	48,764	27,454	12,248	**157,662**

Capital expenditure of USD 157,662 thousand was mainly spent in Malaysia on the A15 sidetrack well completion and in Canada on the production well pump upgrades and additional drilling at Ferguson, Suffield area assets and Onion Lake Thermal.

Net revenues from the Blackrod appraisal project in Canada amounting to USD 7,508 thousand was offset against exploration and evaluation capitalized costs during 2022.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 33,374 thousand as at December 31, 2022, which included USD 31,542 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis based on the Bertam field 2P reserves.

Financial Position and Liquidity

Financing
As at January 2022, IPC had an outstanding EUR 13 million unsecured credit facility in France (the "France Facility"), with maturity in May 2026. IPC commenced quarterly repayments of the French Facility in August 2022. The amount remaining outstanding under the France Facility as at December 31, 2022 was USD 12 million (EUR 11 million).

As at January 2022, the Group had a reserve-based lending (RBL) credit facility of USD 140 million in connection with its oil and gas assets in France and Malaysia and a RBL credit facility of CAD 300 million in connection with its oil and gas assets in Canada.

In February 2022, IPC completed the issuance of USD 300 million of Bonds, which mature in February 2027 and have a fixed coupon rate of 7.25% per annum, payable in semi-annual instalments in August and February. The Group used a portion of the proceeds of the Bonds to fully repay the outstanding RBL credit facilities, which were then cancelled. At the same time, the Group entered into a revolving credit facility of CAD 75 million (the "Canadian RCF") in connection with its oil and gas assets in Canada. The Canadian RCF has a maturity of February 2024 and no cash amounts were drawn under the Canadian RCF as at December 31, 2022.

Total net cash as at December 31, 2022 amounted to USD 175 million.

IPC intends to fund the Cor4 acquisition with cash on hand and the Blackrod Phase 1 development with cash on hand and forecast FCF generated by its operations.

The Bonds repayment obligations as at December 31, 2022, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 3.4 million (EUR 3.2 million) drawn under the France Facility as at December 31, 2022 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants of the Bonds and its financing facilities as at December 31, 2022.

Cash and cash equivalents held amounted to USD 487 million as at December 31, 2022 of which USD 4 million was restricted.

Working Capital
As at December 31, 2022, the Group had a net working capital balance including cash of USD 488,661 thousand compared to USD 56,181 thousand as at December 31, 2021. The difference as at December 31, 2022, from December 31, 2021, is mainly a result of the higher cash balances held following the Bonds issue.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "free cash flow", "EBITDA", "operating costs" and "net debt"/"net cash", which are non-IFRS measures. Non-IFRS measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The Corporation uses non-IFRS measures to provide investors with supplemental measures to assess cash generated by and the financial performance and condition of the Corporation. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Group's ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental measures of operating performance because they highlight trends in the core business that may not otherwise be apparent when relying solely on IFRS financial measures. Management believes such measures allow for assessment of the Group's operating performance and financial condition on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of public companies. Forward-looking statements are provided for the purpose of presenting information about management's current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes.

"Operating cash flow" is calculated as revenue less production costs less current tax. Operating cash flow is used to analyze the amount of cash that is being generated available for capital investment and servicing debt.

"Free cash flow" is calculated as operating cash flow less capital expenditures less decommissioning and farm-in expenditures less general, administration and depreciation expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

"EBITDA" is calculated as net result before financial items, taxes, depletion of oil and gas properties, exploration costs, impairment costs and depreciation and adjusted for non-recurring profit/loss on sale of assets and other income.

"Operating cost" is calculated as production costs excluding any change in the inventory position and the cost of blending and is used to analyze the cash cost of producing the oil and gas volumes.

"Net debt" is calculated as bank loans and Bonds less cash and cash equivalents. "Net cash" is calculated as cash and cash equivalents less bank loans and Bonds.

Reconciliation of Non-IFRS Measures

Operating cash flow
The following table sets out how operating cash flow is calculated from figures shown in the Financial Statements:

	Three months ended December 31		Year ended December 31	
USD Thousands	2022	2021	2022	2021
Revenue	256,479	215,296	1,135,958	666,409
Production costs	(127,495)	(102,561)	(483,646)	(325,007)
Current tax	(15,316)	(2,048)	(29,365)	(4,670)
Operating cash flow	**113,668**	110,687	**622,947**	336,732

Free cash flow
The following table sets out how free cash flow is calculated from figures shown in the Financial Statements:

	Three months ended December 31		Year ended December 31	
USD Thousands	2022	2021	2022	2021
Operating cash flow - see above	113,668	110,687	622,947	336,732
Capital expenditures	(42,792)	(17,441)	(157,662)	(43,990)
Abandonment and farm-in expenditures[1]	(1,085)	(1,282)	(6,962)	(4,546)
General, administration and depreciation expenses before depreciation[2]	(3,333)	(2,648)	(12,832)	(10,648)
Cash financial items[3]	(1,170)	(2,356)	(15,249)	(14,664)
Free cash flow	**65,288**	86,960	**430,242**	262,884

[1] *See note 19 to the Financial Statements*
[2] *Depreciation is not specifically disclosed in the Financial Statements*
[3] *See notes 5 and 6 to the Financial Statements.*

EBITDA
The following table sets out the reconciliation from net result from the consolidated statement of operations to EBITDA:

	Three months ended December 31		Year ended December 31	
USD Thousands	2022	2021	2022	2021
Net result	61,183	66,918	337,725	146,059
Net financial items	6,002	4,079	37,131	30,214
Income tax	24,486	5,408	127,413	21,684
Depletion	30,320	30,293	122,041	119,013
Depreciation of other tangible fixed assets	2,695	2,628	10,787	10,108
Exploration and business development costs	558	345	2,775	1,960
Depreciation included in general, administration and depreciation expenses[1]	407	416	1,608	1,716
EBITDA	**125,651**	**110,087**	**639,480**	330,754

[1] *Item is not shown in the Financial Statements.*

Operating costs
The following table sets out how operating costs is calculated:

	Three months ended December 31		Year ended December 31	
USD Thousands	2022	2021	2022	2021
Production costs	127,495	102,561	483,646	325,007
Cost of blending	(46,534)	(22,323)	(189,172)	(78,434)
Change in inventory position	(4,592)	(15,296)	(158)	1,656
Operating costs	**76,369**	64,942	**294,316**	248,229

Net cash / (debt)
The following table sets out how net cash / (debt) is calculated from figures shown in the Financial Statements:

USD Thousands	December 31, 2022	December 31, 2021
Bank loans	(12,142)	(113,122)
Bonds	(300,000)	–
Cash and cash equivalents	487,240	18,810
Net cash / (debt)	**175,098**	(94,312)

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued three letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent; (b) CAD 0.7 million in respect of its obligations related to the Ferguson asset, increasing by CAD 0.1 million annually to a maximum of CAD 1.0 million; and (c) CAD 1.3 million in respect of pipeline access.

Outstanding Share Data

The common shares of IPC trade on both the Toronto Stock Exchange and the Nasdaq Stockholm.

As at January 1, 2022, IPC had a total of 155,198,105 common shares issued and outstanding, of which IPC held 1,160,651 common shares in treasury. All common shares held in treasury as at January 1, 2022 were cancelled during January 2022.

During 2022, under the normal course issuer bid / share repurchase program announced in December 2021 and renewed in December 2022 (NCIB), IPC purchased and cancelled an aggregate of 8,951,391 common shares.

During Q2 2022, IPC commenced an offer to repurchase common shares under the substantial issuer bid (SIB). Under the SIB, IPC purchased and cancelled an aggregate of 8,258,064 common shares.

As at December 31, 2022, IPC had a total of 136,827,999 common shares issued and outstanding, with no common shares held treasury.

During 2023, IPC continued repurchasing common shares for cancellation under the NCIB. During the period of January 1 to February 7, 2023, IPC purchased 809,659 common shares, of which 738,243 common shares were cancelled. As at February 7, 2023, IPC had a total of 136,089,756 common shares issued and outstanding, of which IPC held 71,416 common shares in treasury.

Nemesia S.à.r.l., an investment company wholly owned by trusts whose settlor was the late Adolf H. Lundin, owns 40,697,533 common shares in IPC, representing 29.9% of the outstanding common shares as at February 7, 2023.

In addition, IPC has 117,485,389 outstanding class A preferred shares, issued as a part of an internal corporate structuring to a wholly-owned subsidiary of IPC. Such 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.

IPC has 5,115,591 IPC Share Unit Plan awards outstanding as at February 7, 2023 (10,703 awards granted in January 2020, 1,216,409 awards granted in March 2020, 25,335 awards granted in July 2020, 21,216 awards granted in January 2021, 674,225 awards granted in March 2021, 1,716,000 awards granted in May 2021, 10,067 awards granted in July 2021 and 12,543 awards granted in January 2022, 1,421,534 awards granted in March 2022, 5,487 awards granted in July 2022 and 2,072 awards granted in January 2023).

Contractual Obligations and Commitments

In Canada, an oil pipeline from the Onion Lake Thermal field to a gathering system has been built by a third party for the exclusive use of IPC. Onion Lake Thermal oil production is blended with condensate before being transported via the pipeline and is therefore expected to attract improved realized prices as a result of the blended oil. The pipeline is also expected to improve the reliability and uptime of the transportation and production at Onion Lake Thermal. The initial investment in the pipeline was met by the pipeline owner and is to be recovered through an agreed tariff charged to IPC. IPC has committed to a firm transportation service for 15 years from commencement of service in April 2022, with total remaining tariffs committed as shown in the table below:

	2023	2024	2025	2026	2027	Thereafter
Transportation service (MCAD)	27.3	28.0	28.4	29.0	29.0	303.3

In Malaysia, IPC has an obligation to make payments towards historic costs on Block PM307 payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves and which is capped at cumulative production of 27.5 MMboe gross, has been provided for in the Group's Balance Sheet – see Note 19 Provisions of the Financial Statements.

Critical Accounting Policies and Estimates

In connection with the preparation of the Corporation's consolidated financial statements, management has made assumptions and estimates about future events and applied judgments that affect the reported values of assets, liabilities, revenues, expenses and related disclosures. These assumptions, estimates and judgments are based on historical experience, current trends and other factors that they believe to be relevant at the time the financial statements are prepared. The management reviews the accounting policies, assumptions, estimates and judgments to ensure that the financial statements are presented fairly in accordance with IFRS. However, because future events and their effects cannot be determined with certainty, actual results could differ from these assumptions and estimates, and such differences could be material.

Transactions with Related Parties

Orrön Energy (formerly Lundin Energy) has charged the Group USD 605 thousand in respect of office space rental and USD 1,480 thousand in respect of shared services provided during the year 2022. Lundin Foundation has charged the Group USD 200 thousand in respect of sustainability advisory services provided to the Group during the year 2022.

All transactions with related parties are in the normal course of business and are made on the same terms and conditions as with parties at arm's length.

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2022, the Corporation had entered into oil and gas price hedges – see below.

Management believes that the cash resources, other current assets and cash flow from operations are sufficient to finance the Group's operations and capital expenditures program over the next year.

Capital Management
The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern and to meet its committed financial liabilities and work program requirements in order to create shareholder value. The Group may put in place new bonds or credit facilities, repay debt, or pursue other such restructuring activities as appropriate.

Management of the Corporation will continuously monitor and manage the Group's capital, liquidity and net debt position in order to assess the requirement for changes to the capital structure to meet the objectives and to maintain flexibility.

Price of Oil and Gas
Prices of oil and gas are affected by the normal economic drivers of supply and demand as well as by financial investors and market uncertainty. Factors that influence these prices include operational decisions, prices of competing fuels, natural disasters, economic conditions, transportation constraints, political instability or conflicts or actions by major oil exporting countries. Price fluctuations will affect the Group's financial position.

Based on analysis of the circumstances, the management assesses the benefits of forward hedging monthly sales contracts for the purpose of protecting cash flow. If management believes that a hedging contract will appropriately help manage cash flow then it may choose to enter into a commodity price hedge. In addition, see the Financial Position and Liquidity section above regarding applicable credit facility covenants to hedge future production.

The Group had oil price sale financial hedges outstanding as at December 31, 2022, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2023 – December 31, 2023	12,000	WCS/ARV Differential	USD - 10.08/bbl

The Group had gas price sale financial hedges outstanding as at December 31, 2022, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per Day)	Type	Average Pricing
January 1, 2023 – March 31, 2023	35,000	AECO Swap	CAD 6.03/GJ
April 1, 2023 – October 31, 2023	35,000	AECO Swap	CAD 3.95/GJ

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 6,616 thousand as at December 31, 2022.

Currency Risk
The Group's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange. The Group will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.

In October 2022, IPC entered into currency hedge swaps for 2023 to buy CAD 15 million per month, sell USD at an average exchange rate of 1.3619 and to buy EUR 3 million per month, sell USD at an average exchange rate of 1.0000. This is to partially fund operational expenditures in those currencies in Canada and France respectively.

The above hedge is treated as effective and changes to the fair value are reflected in other comprehensive income. The currency hedge swaps had a positive fair value of USD 3,970 thousand as at December 31, 2022.

Interest Rate Risk
Interest rate risk is the risk to earnings due to uncertain future interest rates on borrowings. The Group will take into account the level of external debt, current interest rates and market expectations in comparison to historic trends and volatility in making the decision to hedge.

Credit Risk
The Group may be exposed to third party credit risk through contractual arrangements with counterparties who buy the Group's hydrocarbon products. The Group's policy is to limit credit risk by only entering into oil and gas sales agreements with reputable and creditworthy oil and gas and trading companies. Where it is determined that there is a credit risk for oil and gas sales, the Group's policy is to require credit enhancement from the purchaser.

The Group's policy on joint venture parties is to rely on the provisions of the underlying joint operating agreements to take possession of the licence or the joint venture partner's share of production for non-payment of cash calls or other amounts due. In addition, cash is to be held and transacted only through major banks.

RISK AND UNCERTAINTIES

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

See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

Non Financial Risks

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. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and 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: 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 (SPR) management by the United States, the conflict in Ukraine, the impact of pandemics (including Covid-19), 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.

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 a lighter hydrocarbon (commonly referred to as 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 remain 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.
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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 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.

In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions 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.

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 organizations involved in heavy oil production. It is difficult to assess the overall impact 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.

Physical Risks

Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, droughts, or floods, or long-term shifts in climate patterns with sustained higher temperatures or sea level rise. These physical risks may have financial and operational implications for the Corporation, 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.

Reputational Risks: Reputational risks arise from the surge of 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.

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.

Future Covid-19, including variants, or other pandemics may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in this MD&A that result from, for example, a reduction in demand for oil and gas consumption, lower or volatile commodity prices, reliance on third parties, operational risks and costs and changes in government regulation. The extent to which these pandemics impact IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of any pandemics, their severity, the actions taken to contain such pandemics or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition which could be more significant in upcoming periods as compared with previous periods. Even after these pandemics have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact of these pandemics.

Project Risks: The Group is undertaking various projects, including Phase I 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, 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.

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, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

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.

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 decreasing 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 MD&A 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 MD&A 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 MD&A 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. See also "Reserves and Resource Advisory" below.

SAGD Recovery Process: The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and would use the SAGD process at 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.

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), 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 (including, for example, the Malaysian flagging status for the FPSO Bertam) 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 authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

Change in governments or policies in the countries in which the Group operates may have an impact on the decisions taken and regulations made by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy. The oil and gas industry has become an increasingly political topic, which has resulted in a rise in activism and criticism surrounding oil and gas development, particularly with respect to infrastructure projects. Protests, blockades and demonstrations 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 treaty rights against the federal and certain provincial governments as well as private individuals and companies. 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 majority of 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.

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 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 and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group.

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, 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 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 and make restricted payments, encumber its assets, sell assets and enter into certain merger or consolidation transactions. The failure of the Group to comply with the covenants contained in these facilities 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 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 our 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 petroleum industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and 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 losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases. Similarly, from time to time, the Group may enter into agreements to fix the exchange rate of certain currencies. However, if a currency declines in value compared to another currency, the operation of the Group's assets will not benefit from the fluctuating exchange rate if an agreement has fixed such exchange rate.

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

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

Third-Party Credit Risk: The Group may be exposed to third party credit risk through the contractual arrangements associated with the Group's assets with its current or future joint venture partners, marketers of its petroleum and 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: Certain 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.

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

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

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

Information Security: The Group is 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 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.

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.

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 was the late Adolf H. Lundin ("Nemesia"), owns approximately 29.9% of the aggregate voting 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 that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of Nemesia will not be aligned with the interests of other shareholders.

Financial Risks

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.

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 evaluators. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there will be a credit risk associated with counterparties of the Corporation. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service any debt that it may incur, which could negatively impact the market price of the Common Shares.

Issuance of 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;
- Sales or perceived sales of additional Common Shares;
- Significant acquisitions or business combinations, strategic partnerships, joint ventures or capital;
- Commitments by or involving the Corporation or its competitors; and
- Trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Corporation's business segments or target markets.

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

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures
Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation. Management, under the supervision of the Chief Executive Officer and the Chief Financial Officer, is responsible for the design and operation of disclosure controls and procedures.

Internal Controls over Financial Reporting
Management is also responsible for the design of the Group's internal controls over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. However, due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements and fraud.

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

Control Framework
Management assesses the effectiveness of the Corporation's internal control over financial reporting using the Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A 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 MD&A are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this MD&A, 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:

- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2023 production range, 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 continue to react to recent events and navigate the Corporation through periods of volatile commodity prices;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any pandemics and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our 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;
- Future development potential of the Suffield and Ferguson operations in Canada, including the timing and success of future oil and gas drilling and optimization programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices and net present values;
- Current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal;
- The timing and certainty regarding completion of the proposed acquisition of Cor4, including the ability of the IPC and Cor4 to obtain necessary approvals and otherwise satisfy the conditions to such completion and the absence of material events which may interfere with such completion;
- The ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to Cor4's assets post-completion of the Cor4 acquisition;

- The ability of IPC to integrate Cor4's assets into its current operations;
- The existence of drill-ready opportunities in respect of Cor4's assets and their ability to add further near-term production;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The timing and success of the future development projects and other organic growth opportunities in France;
- The ability to maintain current and forecast production in France;
- The ability of IPC to achieve and maintain current and forecast production in Malaysia;
- The ability to 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 GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's ability to identify and complete future acquisitions; 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 Resource Advisory".

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

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

These include, but are not limited to:

- The risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- The uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Health, safety and environmental risks;
- Commodity price fluctuations;
- Interest rate and exchange rate fluctuations;
- Marketing and transportation;
- Loss of markets;
- Environmental risks;
- Competition;
- Incorrect assessment of the value of acquisitions;
- Failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- The ability to access sufficient capital from internal and external sources;
- Failure to obtain required regulatory and other approvals; and
- Changes in legislation, including but not limited to tax laws, royalties, environmental and abandonment regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive. See also "Risk and Uncertainties"

Estimated FCF generation is based on IPC's current business plans over the periods of 2023 to 2027 and 2028 to 2032. Assumptions include average net production of approximately 50 Mboepd over the period of 2023 to 2027, average net production of approximately 65 Mboepd over the period of 2028 to 2032, average Brent oil prices of USD 75 to 95 per boe escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and as further described in the MCR. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's material change report dated February 7, 2023 (MCR), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2021, (See "Cautionary Statement Regarding Forward-Looking

Information", "Reserves and Resources Advisory" and "Risk and Uncertainties") 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.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCES ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's and Cor4'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 (other than the assets to be acquired in the acquisition of Cor4) are effective as of December 31, 2022, 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, 2022 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, 2022, 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, 2022 price forecasts.

Reserve estimates and estimates of future net revenue in respect of the oil and gas assets of Cor4 are effective as of December 31, 2022, and have been audited by a qualified reserves auditor (as defined in NI 51-101), in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2022, price forecasts.

The price forecasts used in the Sproule and ERCE reports, and in respect of Cor4, are available on the website of Sproule (sproule.com) and are contained in the MCR. These price forecasts are as at December 31, 2022 and may not be reflective of current and future forecast
commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 487 MMboe as at December 31, 2022 (including 15.9 MMboe to be acquired in the proposed acquisition of Cor4), by the mid-point of the 2023 CMD production guidance of 48,000 to 50,000 boepd. Reserves replacement ratio is based on 2P reserves of 270 MMboe as at December 31, 2021, sales production during 2022 of 16.9 MMboe, additions to 2P reserves during 2022 of 218 MMboe (or 234 MMboe including the 2P reserves attributable to the acquisition of the Cor4 assets) and 2P reserves of 471 MMboe (or 487 MMboe including the 2P reserves attributable to the acquisition of the Cor4 assets) as at December 31, 2022.

The product types comprising the 2P reserves described in this MD&A are contained in the MCR. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil reserves/resources disclosed in this MD&A 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 the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as 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 commercial considerations can be clearly defined. Chance of development is the probability of a project being commercially viable.

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 guidance for contingent resources, the chance of commerciality is solely based on the chance of development associated with the resolution of all contingencies required for the re-classification of the contingent resources as reserves. Therefore unrisked 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 MD&A 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 the MD&A.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia, and 2P reserves in respect of the oil and gas assets to be acquired in the acquisition of Cor4, 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 MD&A contains estimates of the net present value of the future net revenue from IPC's reserves and contingent resources and Cor4's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve and resources evaluations will be attained and variances could be material.

The reserves and resources information and data provided in this MD&A present only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2022, which will be filed on SEDAR (accessible at www.sedar.com) on or before April 1, 2023. Further information with respect to IPC's and Cor4's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the MCR available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

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, 2022	22.6	10.3	98.1 MMcf (16.4 Mboe)	49.2
December 31, 2021	21.7	8.5	100.2 MMcf (16.7 Mboe)	46.8
Year ended December 31, 2022				
December 31, 2022	22.6	9.6	98.1MMcf (16.4 Mboe)	48.6
December 31, 2021	20.4	8.4	99.6 MMcf (16.7 Mboe)	45.5

This document also makes reference to IPC's forecast average daily production of 48,000 to 50,000 boepd for 2023. IPC estimates that approximately 50% of that production will be comprised of heavy oil, approximately 17% will be comprised of light and medium crude oil and approximately 33% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	US dollar
MYR	Malaysian Ringgit
FPSO	Floating Production Storage and Offloading (facility)

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 on the API (American Petroleum Institute) gravity scale
	Alkaline surfactant polymer (an EOR process)
ARV	Argus WCS Houston (a reference price for the cost of transporting WCS quality oil from Alberta to Houston)
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion cubic feet
Bscf	Billion standard cubic feet
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
MMcf	Million cubic feet
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage (a thermal recovery process)
WTI	West Texas Intermediate (a light oil reference price)
WCS	Western Canadian Select (a heavy oil reference price)

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

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