Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2022

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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 19.

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 24.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2021, 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, 2021, 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, 2021, 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, 2021, price forecasts.

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

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. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future. 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. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures. See "Risks and Uncertainties".

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 November 1, 2022, 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 unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 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:

	September 30, 2022		September 30, 2021		December 31, 2021	
	Average	Period end	Average	Year end	Average	Year end
1 EUR equals USD	1.0650	0.9748	1.1967	1.1579	1.1835	1.1326
1 USD equals CAD	1.2828	1.3747	1.2515	1.2739	1.2536	1.2708
1 USD equals MYR	4.3422	4.6370	4.1296	4.1865	4.1433	4.1660

HIGHLIGHTS

Q3 2022 Business and Financial Highlights

Q3 2022 Achievements

- Successful conclusion of IPC's first Substantial Issuer Bid (SIB) returning MUSD 100 to participating shareholders and approximately 8.3 million common shares being purchased and cancelled in early July 2022.
- Record spot production rates achieved during the third quarter under IPC operatorship at the Onion Lake Thermal and Ferguson assets in Canada.
- Front End Engineering Design (FEED) studies on the Blackrod project, Canada progressing for scheduled completion by end 2022.
- Release of IPC's third Sustainability Report in August 2022.

Q3 2022 Results

- Record average net production of approximately 50,000 barrels of oil equivalent (boe) per day (boepd) for the third quarter of 2022, above high end guidance (45% heavy crude oil, 21% light and medium crude oil and 34% natural gas).(1)
- Net result of MUSD 91 for the third quarter of 2022.
- Operating costs per boe of USD 15.7 for the third quarter of 2022, below latest guidance.(2)
- Strong operating cash flow (OCF) generation for IPC of MUSD 172 for the third quarter of 2022.(2)
- Capital and decommissioning expenditures of MUSD 47 for the third quarter of 2022 and MUSD 119 for the first nine months of 2022.
- Strong free cash flow (FCF) generation for IPC of MUSD 117 for the third quarter of 2022.(2)
- Net cash of MUSD 89 as at September 30, 2022 (after the funding of a further MUSD 47 of share repurchases during the third quarter).(2)

2022 Annual Guidance

- Full year 2022 average net production expected to be above the upper end of the guidance range of 48,000 boepd.(1)
- Full year 2022 operating costs guidance retained at between USD 16 to 17 per boe.(2)
- Full year 2022 OCF guidance tightened to between MUSD 620 to 655 (Brent USD 85 to 100 per barrel for the remainder of 2022).(2)
- Full year 2022 capital and decommissioning expenditures guidance retained at MUSD 170.
- Full year 2022 FCF guidance tightened to between MUSD 425 to 460 (Brent USD 85 to 100 per barrel for the remainder of 2022).(2)

Reserves and Resources

- Proved plus probable (2P) reserves as at December 31, 2021 of 270 million boe (MMboe), with a reserves life index (RLI) of 16 years.(1)(3)
- Contingent resources (best estimate, unrisked) as at December 31, 2021 of 1,410 MMboe.(1)(3)

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	**2022**	2021	**2022**	2021
Revenue	**300,770**	172,551	**879,479**	451,113
Gross profit	**140,489**	58,636	**421,298**	130,852
Net result	**90,503**	30,557	**276,542**	79,141
Operating cash flow(2)	**171,654**	91,365	**509,279**	226,045
Free cash flow(2)	**116,681**	76,607	**364,954**	175,924
EBITDA(2)	**174,328**	89,223	**513,829**	220,667
Net Cash / (Debt)(2)	**88,615**	(161,199)	**88,615**	(161,199)

OPERATIONS REVIEW

Business Overview

During the third quarter of 2022, oil and gas prices retreated from second quarter highs 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. Brent prices averaged USD 101 per barrel during the third quarter of 2022, lower than average second quarter Brent pricing of USD 114 per barrel.

In Canada, third quarter 2022 Western Canadian Select (WCS) crude price differentials to West Texas Intermediate (WTI) averaged USD 20 per barrel, USD 7 per barrel wider than the second quarter 2022. Forward markets into 2023 are also pricing the WCS differential to WTI wider at around USD 20 per barrel. Market commentators believe that a combination of higher natural gas prices for refiners, discounted Russian heavy barrels, US refinery outages as well as the SPR releases being mostly heavier barrels, are behind the increase in the WCS differential. IPC positioned itself well to mitigate this widening in the second half of 2022 with approximately two-thirds of our WCS differential exposure hedged at around USD 13 per barrel. In October 2022, IPC hedged the WCS/ARV (Argus WCS Houston) differential for 2023 for 12,000 bopd of Canadian oil production at USD 10 per barrel. This differential stands for the cost to transport a barrel of WCS quality oil from Hardisty (Alberta, Canada) to Houston (USA).

Gas markets remained relatively strong during the third quarter of 2022. IPC's average realised gas price was CAD 5.80 per Mcf, well above the average second quarter AECO benchmark price of CAD 4.10 per Mcf as IPC benefitted from higher Empress pricing. Forward prices remain high at above CAD 5.00 per Mcf for 2023. IPC currently has no gas hedges in place.

IPC benefits from a well balanced mix of production comprising approximately 50% Canadian Crude, 33% Canadian Natural Gas and 17% Brent weighted oil in 2022. With synchronized strength in pricing across the entire energy complex, combined with delivering operational excellence above the high end of our third quarter forecast, IPC has again been able to deliver a very strong financial performance in the third quarter.

We have created significant value from acquisition for all of our stakeholders having concluded four acquisitions in the past four years and will remain opportunistic in our approach with respect to further M&A activity focusing on securing additional high quality resources, as well as maturing our significant contingent resource base in excess of 1.4 billion barrels.(3)

Third Quarter 2022 Highlights

During the third quarter of 2022, our assets delivered average net production of 50,000 boepd, above our high end guidance for the quarter and achieving a record high for IPC. 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. With year to date average net production of 48,400 boepd, we expect full year 2022 average net production to remain above the upper end of the guidance range of 48,000 boepd.(1)

Our operating costs per boe for the third quarter of 2022 was USD 15.7, below our latest guidance. Year to date operating costs per boe was USD 16.5 and we are retaining our full year 2022 guidance of USD 16 to 17 per boe.(2)

Operating cash flow (OCF) generation for the third quarter of 2022 was USD 172 million. Full year 2022 OCF guidance is being tightened from USD 595 to 730 million (Brent USD 85 to 115 per barrel) to USD 620 to 655 million (Brent USD 85 to 100 per barrel for the remainder of 2022).(2)

Capital and decommissioning expenditure for the third quarter of 2022 was USD 47 million and USD 119 million for the first nine months of 2022. Full year 2022 capital and decommissioning expenditure guidance is retained at USD 170 million.

Free cash flow (FCF) generation was very strong at USD 117 million during the third quarter of 2022. Full year 2022 FCF guidance is being tightened from USD 395 to 530 million (Brent USD 85 to 115 per barrel) to USD 425 to 460 million (Brent USD 85 to 100 per barrel for the remainder of 2022). This represents between 33% and 35% of IPC's current market capitalization. (2)(4)

During the third quarter of 2022, IPC's net cash position was further strengthened with a build to USD 89 million, net of funding a further USD 47 million of share repurchases under our normal course issuer bid (NCIB) during the third quarter.(2)

IPC forecasts cumulative FCF for 2022 to 2026 of approximately USD 900 to 1,800 million (based on forecast Brent oil prices of USD 65 to 95 per barrel) generating estimated average annual FCF yield over the five year period of between 14% and 28%. (2)(4)

Share Repurchase Programs

Substantial Issuer Bid

As previously announced, we were very pleased to have concluded our first Substantial Issuer Bid (SIB) in line with our capital allocation framework to materially increase returns to shareholders in the higher oil price environment. IPC returned USD 100 million to participating shareholders, with our remaining shareholders benefiting from the cancellation of the repurchased shares, being approximately 5.5% of the total number of issued and outstanding shares. In early July 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

Following the completion of the SIB, IPC continued to distribute value to our shareholders by restarting share repurchases under our previously announced NCIB. IPC implemented the current NCIB in December 2021. This program permits IPC to buy-back up to approximately 11.1 million shares, or approximately 7% of the total outstanding IPC shares at the time of launch, over the 12-month period up to December 2022. To date, IPC has purchased and cancelled approximately 9.3 million IPC shares under the NCIB at a total purchase cost of approximately USD 76 million. The average price of IPC shares purchased to date under the NCIB is approximately SEK 82 per share.

Since inception, IPC has repurchased a total of approximately 51 million IPC shares at an average price of SEK 56 per share. As at November 1, 2022, IPC had a total of 137,842,861 common shares issued and outstanding.

Environmental, Social and Governance (ESG) Performance

ESG performance remains a priority for all operational assets. Our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During the third quarter of 2022, IPC recorded no material safety or environmental incidents.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2021 (AIF) available on IPC's website at www.international- petroleum.com and under IPC's profile on SEDAR at www.sedar.com.

(2) Non-IFRS measure, see "Non-IFRS Measures" below.

(3) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, are further described in the AIF.

(4) Estimated FCF generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production over that period of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the AIF. Free cash flow yield is based on IPC's market capitalization at close October 28, 2022 (104.1 SEK/share, 11.0 SEK/USD, USD 1,307 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

Reserves and Resources

The 2P reserves attributable to IPC's oil and gas assets are 270 MMboe as at December 31, 2021, as certified by independent third party reserve auditors. The reserve life index (RLI) as at December 31, 2021, is approximately 16 years. Best estimate contingent resources as at December 31, 2021, are 1,410 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC set a balanced capital budget for 2022, targeting production growth 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. In France, the Villeperdue West drilling preparations are in line with schedule, with the expectation that the majority of the project will be executed in 2022. IPC remains focused on organic growth and continues to mature future development projects across all operated assets, with a significant portfolio of drilling and optimisation opportunities ready for sanction at the discretion of the Group.

Production

In Q3 2022, for the second consecutive quarter, IPC achieved a new production record with average daily net production above the high end of the CMD guidance range at 50,000 boepd. Strong operational performance and high production uptimes have been supplemented by the production benefit from the recent development investments in Canada and Malaysia. In Canada, base optimisation activity at our Suffield assets continues to deliver strong results and for the third quarter in succession Onion Lake Thermal delivered record production. In addition, strong performance from the Malaysian and French assets continued in Q3 2022 with excellent operational uptime at the Bertam field in Malaysia and stable production in France.

The production during Q3 2022 with comparatives is summarized below:

Production in Mboepd	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
	2022	2021	**2022**	2021	2021
Crude oil					
Canada – Northern Assets	15.8	14.1	15.4	12.4	12.8
Canada – Southern Assets	8.8	8.7	8.5	8.7	8.6
Malaysia	5.8	4.2	5.3	4.3	4.4
France	2.7	3.0	2.8	3.0	3.0
Total crude oil production	**33.1**	30.0	**32.0**	28.4	28.8
Gas					
Canada – Northern Assets	0.1	0.1	0.1	0.1	0.1
Canada – Southern Assets	16.8	16.7	16.3	16.6	16.6
Total gas production	**16.9**	16.8	**16.4**	16.7	16.7
Total production	**50.0**	46.8	**48.4**	45.1	45.5
Quantity in MMboe	**4.60**	4.31	**13.21**	12.30	16.61

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

CANADA

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2022	2021	**2022**	2021	2021
- Oil Onion Lake Thermal	100%	12.9	11.5	12.5	10.2	10.6
- Oil Suffield	100%	6.9	7.6	7.2	7.6	7.5
- Oil Ferguson	100%	1.9	1.1	1.3	1.1	1.1
- Oil Other	50-100%	2.9	2.6	2.9	2.2	2.2
- Gas	99.7%[1]	16.9	16.8	16.4	16.7	16.7
Canada		**41.5**	39.6	**40.3**	37.8	38.1

[1] *On a well count basis*

Production
Net production from IPC's Canadian assets during Q3 2022 was ahead of the CMD forecast at 41,500 boepd with continued strong reservoir performance and high production uptime at all the oil and gas producing assets. Optimisation activity at the Suffield property continue to deliver strong results and offset field decline rates. For the third quarter in succession, Onion Lake Thermal delivered record production with strong base well performance.

Organic Growth and Capital Projects
In Canada, a diverse program of drilling and optimisation projects are budgeted for 2022. In addition, IPC has sanctioned the Blackrod Phase 1 commercial development Front End Engineering Design ("FEED") study with completion expected in late 2022. 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 further conventional oil well drilling, gas recompletion activity and facility capacity optimisation.

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. In Q3 2022, drilling activity continued at the next production sustaining Pad L.

At Ferguson, IPC sanctioned the first phase of the planned field development, including sixteen new horizontal producers and gas processing system capacity increases as part of the program. As of the end of Q3 2022, the sixteen production wells have been drilled and fourteen have been brought online with daily production at the Ferguson asset touching 3,000 boepd for the first time under IPC operatorship.

In Q3 2022, IPC commenced oil drilling activity at the Suffield Oil asset. As of the end of Q3 2022, drilling of two ASP injection and two production wells had been completed as part of a planned expansion of the N2N EOR field, with completions and first oil from the expansion project expected in Q4 2022. Two further conventional production and two water disposal wells are scheduled for drilling through Q4 2022.

By the end of Q3 2022 at Suffield Gas, all 110 planned gas well recompletions had been executed and brought onstream. At the end of Q3 2022, seventeen additional recompletions had been identified and sanctioned for planned execution in Q4 2022.

Strong performance from the third well pair pilot project at the Blackrod asset continued through Q3 2022. Heat conformance and production performance remain ahead of expectation. As of the end of Q3 2022, Blackrod Phase 1 commercial development FEED studies have progressed in line with schedule.

MALAYSIA

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2022	2021	**2022**	2021	2021
Bertam	100% [1]	**5.8**	4.2	**5.3**	4.3	4.4

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

Production

Net production from the Bertam field on Block PM307 during Q3 2022 was stable and in line with CMD guidance at 5,800 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.

FRANCE

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2022	2021	**2022**	2021	2021
France						
- Paris Basin	100%[1]	2.4	2.6	2.5	2.6	2.6
- Aquitaine	50%	0.3	0.4	0.3	0.4	0.4
		2.7	3.0	**2.8**	3.0	3.0

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

Production

Net production in France during Q3 2022 was in line with CMD guidance at 2,700 boepd with stable production and good uptime 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.

The planned Villeperdue West drilling program is progressing, with the first well in the program spud in late October 2022.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q3-22	Q2-22	Q1-22	Q4-21	Q3-21	Q2-21	Q1-21	Q4-20
Revenue	**300,770**	317,403	261,306	215,296	172,551	144,278	134,284	103,353
Gross profit	**140,489**	161,709	119,100	79,469	58,636	34,286	37,930	(60,570)
Net result	**90,503**	105,217	80,822	66,918	30,557	21,693	26,891	(45,250)
Earnings per share – USD	**0.63**	0.70	0.52	0.43	0.20	0.14	0.17	(0.29)
Earnings per share fully diluted – USD	**0.62**	0.68	0.51	0.42	0.19	0.14	0.17	(0.29)
Operating cash flow[1]	**171,654**	192,515	145,110	110,687	91,365	66,959	67,721	46,019
Free cash flow[1]	**116,681**	151,792	96,479	86,960	76,607	50,366	48,951	28,571
EBITDA[1]	**174,328**	194,038	145,463	110,087	89,223	65,181	66,263	43,004
Net cash / (debt) at period end[1]	**88,615**	14,382	(42,367)	(94,312)	(161,199)	(240,617)	(286,132)	(321,193)

[1] *See definition on page 19 under "Non-IFRS measures"*

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2022	December 31, 2021
Non-current assets	991,272	1,122,514
Current assets	577,934	151,160
Total assets	**1,569,206**	1,273,674
Total non-current liabilities	540,086	331,152
Current liabilities	135,758	94,979
Total liabilities	**675,844**	426,131
Net assets	**893,362**	847,543
Working capital (including cash)	**442,176**	56,181

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 – September 30, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	123,542	64,083	71,138	21,884	–	**280,647**
NGLs	–	170	–	–	–	**170**
Gas	173	37,224	–	–	–	**37,397**
Net sales of oil and gas	**123,715**	**101,477**	**71,138**	**21,884**	–	**318,214**
Change in under/over lift position	–	–	–	534	–	**534**
Royalties	(13,542)	(12,985)	–	–	–	**(26,527)**
Hedging settlement	6,564	1,832	–	–	–	**8,396**
Other operating revenue	–	10	–	143	–	**153**
Revenue	**116,737**	**90,334**	**71,138**	**22,561**	–	**300,770**
Operating costs	(23,538)	(29,867)	(9,249)	(9,758)	–	**(72,412)**
Cost of blending	(35,563)	(6,795)	–	–	–	**(42,358)**
Change in inventory position	(219)	(749)	(8,488)	162	–	**(9,294)**
Depletion	(8,488)	(10,965)	(9,618)	(2,868)	–	**(31,939)**
Depreciation of other assets	–	–	(2,991)	–	–	**(2,991)**
Exploration and business development costs	–	–	–	–	(1,287)	**(1,287)**
Gross profit/(loss)	**48,929**	**41,958**	**40,792**	**10,097**	**(1,287)**	**140,489**

	Three months ended – September 30, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	74,909	50,907	22,206	17,335	–	165,357
NGLs	–	133	–	–	–	133
Gas	165	25,474	–	–	–	25,639
Net sales of oil and gas	75,074	76,514	22,206	17,335	–	191,129
Change in under/over lift position	–	–	–	3,439	–	3,439
Royalties	(7,948)	(5,772)	–	–	–	(13,720)
Hedging settlement	(6,808)	(1,699)	–	–	–	(8,507)
Other operating revenue	–	–	–	210	–	210
Revenue	60,318	69,043	22,206	20,984	–	172,551
Operating costs	(21,120)	(24,924)	(8,231)	(8,932)	–	(63,207)
Cost of blending	(12,103)	(5,972)	–	–	–	(18,075)
Change in inventory position	25	(97)	781	(38)	–	671
Depletion	(8,120)	(10,868)	(7,288)	(4,177)	–	(30,453)
Depreciation of other assets	–	–	(2,443)	–	–	(2,443)
Exploration and business development costs	–	–	–	–	(408)	(408)
Gross profit/(loss)	19,000	27,182	5,025	7,837	(408)	58,636

	Nine months ended – September 30, 2022					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	412,222	212,295	139,782	83,284	–	**847,583**
NGLs	–	632	–	–	–	**632**
Gas	826	118,016	–	–	–	**118,842**
Net sales of oil and gas	**413,048**	**330,943**	**139,782**	**83,284**	–	**967,057**
Change in under/over lift position	–	–	–	(911)	–	**(911)**
Royalties	(49,347)	(37,514)	–	–	–	**(86,861)**
Hedging settlement	6,534	(6,994)	–	–	–	**(460)**
Other operating revenue	–	111	–	543	–	**654**
Revenue	**370,235**	**286,546**	**139,782**	**82,916**	–	**879,479**
Operating costs	(78,196)	(82,610)	(25,657)	(31,484)	–	**(217,947)**
Cost of blending	(115,881)	(26,757)	–	–	–	**(142,638)**
Change in inventory position	1,272	193	2,195	774	–	**4,434**
Depletion	(24,841)	(31,389)	(26,020)	(9,471)	–	**(91,721)**
Depreciation of other assets	–	–	(8,092)	–	–	**(8,092)**
Exploration and business development costs	97	–	–	–	(2,314)	**(2,217)**
Gross profit/(loss)	**152,686**	**145,983**	**82,208**	**42,735**	**(2,314)**	**421,298**

	Nine months ended – September 30, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	184,364	136,347	53,270	57,086	–	431,067
NGLs	–	398	–	–	–	398
Gas	418	66,313	–	–	–	66,731
Net sales of oil and gas	184,782	203,058	53,270	57,086	–	498,196
Change in under/over lift position	–	–	–	2,433	–	2,433
Royalties	(17,211)	(14,150)	–	–	–	(31,361)
Hedging settlement	(15,163)	(7,997)	–	–	–	(23,160)
Other operating revenue	–	–	4,208	733	64	5,005
Revenue	152,408	180,911	57,478	60,252	64	451,113
Operating costs	(58,257)	(74,672)	(21,117)	(29,242)	–	(183,287)
Cost of blending	(37,416)	(18,695)	–	–	–	(56,111)
Change in inventory position	558	349	15,857	188	–	16,952
Depletion	(21,546)	(32,339)	(22,313)	(12,522)	–	(88,720)
Depreciation of other assets	–	–	(7,480)	–	–	(7,480)
Exploration and business development costs	(4)	–	(259)	(7)	(1,345)	(1,615)
Gross profit/(loss)	35,743	55,554	22,167	18,669	(1,281)	130,852

Three and nine months ended September 30, 2022, Review

Revenue

Total revenue amounted to USD 300,770 thousand for Q3 2022, compared to USD 172,551 thousand for Q3 2021 and USD 879,479 thousand for the first nine months of 2022 compared to USD 451,113 thousand for the first nine months of 2021 and is analyzed as follows:

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	**2022**	2021	**2022**	2021
Crude oil sales	280,647	165,357	847,583	431,067
Gas and NGL sales	37,567	25,772	119,474	67,129
Change in under/overlift position	534	3,439	(911)	2,433
Royalties	(26,527)	(13,720)	(86,861)	(31,361)
Hedging settlement	8,396	(8,507)	(460)	(23,160)
Other operating revenue	153	210	654	5,005
Total revenue	**300,770**	172,551	**879,479**	451,113

The main components of total revenue for the three and nine months ended September 30, 2022, and September 30, 2021, respectively, are detailed below.

Crude oil sales

	Three months ended – September 30, 2022				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	123,542	64,083	71,138	21,884	**280,647**
- Quantity sold in bbls	1,743,766	887,736	614,329	217,875	**3,463,706**
- Average price realized USD per bbl	70.85	72.19	115.80	100.44	**81.03**

	Three months ended – September 30, 2021				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	74,909	50,907	22,206	17,335	165,357
- Quantity sold in bbls	1,384,177	895,217	302,700	236,357	2,818,451
- Average price realized USD per bbl	54.12	56.87	73.36	73.34	58.67

Crude oil revenue was 70 per cent higher in Q3 2022 compared to Q3 2021 mainly due to higher oil prices caused by the continuing tight market supply and the conflict in Ukraine. Oil prices were slightly down in Q3 2022 versus the previous quarter following recessionary fears and the impact of Covid-19 lockdowns in China on demand.

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 Q3 2022, WTI averaged USD 92 per bbl compared to USD 71 per bbl for Q3 2021 and the average discount to WCS used in our pricing formula was USD 20 per bbl compared to USD 14 per bbl for Q3 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 Q3 2022 in July and September compared to one cargo lifting in Q3 2021. Produced unsold oil barrels from Bertam at the end of Q3 2022 amounted to 158,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo in France lifted in Q3 2022, nor Q3 2021. The average Dated Brent crude oil price was USD 101 per bbl for Q3 2022 compared to USD 73 per bbl for the comparative period.

USD Thousands	Nine months ended – September, 2022				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	412,222	212,295	139,782	83,284	**847,583**
- Quantity sold in bbls	5,055,871	2,591,889	1,173,230	813,116	**9,634,106**
- Average price realized USD per bbl	81.53	81.91	119.14	102.43	**87.98**

USD Thousands	Nine months ended – September 30, 2021				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	184,364	136,347	53,270	57,086	431,067
- Quantity sold in bbls	3,713,072	2,631,808	760,088	833,355	7,938,323
- Average price realized USD per bbl	49.65	51.81	70.08	68.50	54.30

Crude oil revenue was nearly double the amount in the first nine months of 2022 compared to the first nine months of 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"). For the first nine months of 2022, WTI averaged USD 98 per bbl compared to USD 65 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 16 per bbl compared to USD 13 per bbl for the comparative period.

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 106 per bbl for the first nine months of 2022 compared to USD 68 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – September 30, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	37,394	173	**37,567**
- Quantity sold in Mcf	8,478,728	58,742	**8,537,470**
- Average price realized USD per Mcf	4.41	2.95	**4.40**

	Three months ended – September 30, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	25,607	165	25,772
- Quantity sold in Mcf	8,612,728	61,546	8,674,274
- Average price realized USD per Mcf	2.97	2.68	2.97

Gas and NGL sales revenue was 46% higher for Q3 2022 compared to Q3 2021 mainly due to the higher achieved gas price. IPC's achieved gas price is based on AECO pricing plus a premium. For Q3 2022, IPC realized an average price of CAD 5.75 per Mcf compared to AECO average pricing of CAD 4.08 per Mcf.

	Nine months ended – September 30, 2022		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	118,648	826	**119,474**
- Quantity sold in Mcf	24,443,007	194,580	**24,637,587**
- Average price realized USD per Mcf	4.85	4.24	**4.85**

	Nine months ended – September 30, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	66,711	418	67,129
- Quantity sold in Mcf	25,194,386	167,846	25,362,232
- Average price realized USD per Mcf	2.65	2.49	2.65

Gas and NGL sales revenue was 78% higher for the first nine months of 2022 compared to the first nine months of 2021 mainly due to the higher achieved gas price. For the first nine months of 2022, IPC realized an average price of CAD 6.22 per Mcf compared to AECO average pricing of CAD 5.30 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 first nine months of 2022 amounted to a loss of USD 460 thousand and consisted of a loss of USD 10,631 thousand on the gas contracts and a gain of USD 10,171 thousand on the oil contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Other operating revenue
Other operating revenue amounted to USD 153 thousand for Q3 2022 compared to USD 210 thousand for Q3 2021 and USD 654 thousand for the first nine months of 2022 compared to USD 5,005 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 124,064 thousand for Q3 2022 compared to USD 80,611 thousand for Q3 2021 and USD 356,151 thousand for the first nine months of 2022 compared to USD 222,446 thousand for the comparative period, and is analyzed as follows:

	Three months ended – September 30, 2022					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	29,867	23,538	13,389	9,758	(4,140)	**72,412**
USD/boe[2]	12.68	16.08	25.07	39.44	n/a	**15.74**
Cost of blending	6,795	35,563	–	–	–	**42,358**
Change in inventory position	749	219	8,488	(162)	–	**9,294**
Production costs	**37,411**	**59,320**	**21,877**	**9,596**	**(4,140)**	**124,064**

USD Thousands	Three months ended – September 30, 2021					
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	24,924	21,120	12,118	8,932	(3,887)	63,207
USD/boe[2]	10.69	16.09	31.33	32.39	n/a	14.68
Cost of blending	5,972	12,103	–	–	–	18,075
Change in inventory position	97	(25)	(781)	38	–	(671)
Production costs	30,993	33,198	11,337	8,970	(3,887)	80,611

USD Thousands	Nine months ended – September 30, 2022					
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	82,610	78,196	37,942	31,484	(12,285)	**217,947**
USD/boe[2]	12.20	18.46	26.26	41.33	n/a	**16.49**
Cost of blending	26,757	115,881	–	–	–	**142,638**
Change in inventory position	(193)	(1,272)	(2,195)	(774)	–	**(4,434)**
Production costs	**109,174**	**192,805**	**35,747**	**30,710**	**(12,285)**	**356,151**

USD Thousands	Nine months ended – September 30, 2021					
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	74,672	58,257	41,316	29,242	(20,200)	183,287
USD/boe[2]	10.85	17.07	34.88	35.64	n/a	14.90
Cost of blending	18,695	37,416	–	–	–	56,111
Change in inventory position	(349)	(558)	(15,857)	(188)	–	(16,952)
Production costs	93,018	95,115	25,459	29,054	(20,200)	222,446

[1] *See definition on page 19 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 17.32 and USD 21.28 for Q3 2022 and Q3 2021 respectively and USD 17.76 and USD 17.83 for the nine months ended September 30, 2022, and September 30, 2021, respectively.*

Operating costs
Operating costs amounted to USD 72,412 thousand for Q3 2022 compared to USD 63,207 thousand for Q3 2021 and USD 217,947 thousand for the first nine months of 2022 compared to USD 183,287 for the first nine months of 2021. The increase in costs in Q3 2022 compared to Q3 2021 is due to higher energy prices, higher chemical costs and increased activity. Operating costs per boe amounted to USD 15.74 per boe in Q3 2022 compared with USD 14.68 per boe in Q3 2021 and was below latest guidance for Q3 2022. Operating costs for the first nine months of 2022 amount to USD 16.49 per boe and the full year operating cost guidance is retained at 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. Since July 2020, a portion of Onion Lake oil production has been blended and exported by pipeline. From April 2022, the Husky export pipeline from the Onion Lake field to the gathering system was commissioned and a greater portion of Onion Lake Thermal crude oil production is being blended and exported by pipeline improving the reliability and uptime of the production.

The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 42,358 thousand for Q3 2022 compared to USD 18,075 thousand for Q3 2021 and USD 142,638 thousand for the first nine months of 2022 compared to USD 56,111 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 Q3 2022, IPC had crude entitlement of 158,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold). A crude cargo was lifted from Bertam in September 2022 with the next lifting expected in November 2022.

Depletion and decommissioning costs
The total depletion of oil and gas properties amounted to USD 31,939 thousand for Q3 2022 compared to USD 30,453 thousand for Q3 2021 and USD 91,721 thousand for the first nine months of 2022 compared to USD 88,720 thousand for the first nine months of 2021. The depletion charge is analyzed in the following tables:

	Three months ended – September 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,964	8,488	9,618	2,868	**31,939**
USD per boe	4.66	5.80	18.01	11.59	**6.94**

	Three months ended – September 30, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,868	8,120	7,288	4,177	30,453
USD per boe	4.66	6.19	18.84	15.15	7.07

	Nine months ended – September 30, 2022				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	31,389	24,841	26,020	9,471	**91,721**
USD per boe	4.63	5.87	18.01	12.43	**6.94**

	Nine months ended – September 30, 2021				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	32,339	21,546	22,313	12,522	88,720
USD per boe	4.70	6.31	18.84	15.26	7.21

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 2,991 thousand for Q3 2022 compared to USD 2,443 thousand for Q3 2021 and USD 8,092 thousand for the first nine months of 2022 compared to USD 7,480 thousand for the first nine months of 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.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 1,287 thousand for Q3 2022 and USD 2,217 thousand for the first nine months of 2022.These costs mainly related to business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 2,784 thousand for Q3 2022, compared to USD 3,131 thousand for Q3 2021 and USD 10,700 thousand for the first nine months of 2022 compared to USD 9,300 thousand for the first nine months of 2021.

Net financial items
Net financial items amounted to a charge of USD 9,225 thousand for Q3 2022, compared to a charge of USD 12,960 thousand for Q3 2021 and a charge of USD 31,129 thousand for the first nine months of 2022 compared to a charge of USD 26,135 thousand for the first nine months of 2021, and included a largely non-cash net foreign exchange loss of USD 5,945 thousand for the first nine months of 2022 compared to a net foreign exchange loss of USD 3,558 thousand for the first nine months of 2021. The foreign exchange movements during the first nine months of 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 7,323 thousand for Q3 2022, compared to USD 6,336 thousand for Q3 2021 and a charge of USD 25,184 thousand for the first nine months of 2022 compared to a charge of USD 22,577 thousand for the comparative period.

The interest expense amounted to USD 5,686 thousand for Q3 2022, compared to USD 2,664 thousand for the comparative period in 2021 and USD 15,201 thousand for the first nine months of 2022 compared to USD 10,994 thousand for the first nine months of 2021. Despite the repayment of the outstanding reserve-based lending (RBL) credit facilities in February 2022, the cost of financing was higher in the first nine months of 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.

Following the repayment of the outstanding RBL credit facilities with a portion of the Bonds proceeds, the remaining capitalized loan fees have been 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 2,949 thousand for the first nine months of 2022 compared to USD 1,602 thousand for the comparative period in 2021.

The unwinding of the asset retirement obligation discount rate amounted to USD 2,667 thousand for Q3 2022, compared to USD 2,869 thousand for Q3 2021 and USD 8,156 thousand for the first nine months of 2022 compared to USD 8,667 thousand for the first nine months of 2021.

Income tax
The corporate income tax amounted to a charge of USD 37,977 thousand for Q3 2022, compared to a charge of USD 11,988 thousand for Q3 2021 and a charge of USD 102,927 thousand for the first nine months of 2022 compared to a charge of USD 16,276 thousand for the first nine months of 2021. The income tax movements in Q3 2022 mainly relate to deferred taxes with low cash taxes reflected. No corporate income tax is payable in Canada in Q3 2022 due to the usage of historical tax pools.

As per note 21 Subsequent events of the Financial Statements, 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. This tax or "Solidarity Contribution" is to be calculated on taxable profits in 2022 and/or 2023 that are above a 20 percent increase of the average yearly taxable profits over the period 2018 to 2021, at a minimal rate of 33%, in addition to the standard corporate income tax. The Solidarity Contribution is expected to be applicable to the Group's income in France and a provisional estimate amounts to MEUR 12 for 2022 and is expected to be payable in Q2 2023. An amendment to the French finance law has been published on October 7, 2022 which is expected to be approved before year end 2022.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first nine months of 2022, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	56,617	32,755	26,948	2,352	**118,672**
Exploration and evaluation	–	(3,881)	76	3	**(3,802)**
	56,617	28,874	27,024	2,355	**114,870**

Capital expenditure of USD 114,870 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 7,088 thousand is being offset against exploration and evaluation capitalized costs.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 34,339 thousand as at September 30, 2022, which included USD 32,401 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
In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility"). In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments which commenced in August 2022. The amount remaining outstanding under the France Facility as at September 30, 2022 was EUR 12 million.

In 2021, the Group had a reserve-based lending (RBL) credit facility of USD 140 million with a maturity to end of December 2024 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had a RBL credit facility of CAD 300 million with a maturity date in May 2023, 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 September 30, 2022.

Total net cash as at September 30, 2022 amounted to USD 89 million.

The amounts drawn under the Bonds as at September 30, 2022, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 3.1 million drawn under the France Facility as at September 30, 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 September 30, 2022.

Cash and cash equivalents held amounted to USD 400 million as at September 30, 2022.

Working Capital
As at September 30, 2022, the Group had a net working capital balance including cash of USD 442,176 thousand compared to USD 56,181 thousand as at December 31, 2021. The difference as at September 30, 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 - September 30		Nine months ended - September 30	
USD Thousands	2022	2021	2022	2021
Revenue	300,770	172,551	879,479	451,113
Production costs	(124,064)	(80,611)	(356,151)	(222,446)
Current tax	(5,052)	(575)	(14,049)	(2,622)
Operating cash flow	**171,654**	91,365	**509,279**	226,045

Free cash flow

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

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	2022	2021	2022	2021
Operating cash flow - see above	171,654	91,365	509,279	226,045
Capital expenditures	(46,729)	(7,663)	(114,870)	(26,549)
Abandonment and farm-in expenditures[1]	(1,517)	(1,376)	(5,877)	(3,264)
General, administration and depreciation expenses before depreciation[2]	(2,378)	(2,717)	(9,499)	(8,000)
Cash financial items[3]	(4,349)	(3,002)	(14,079)	(12,308)
Free cash flow	**116,681**	76,607	**364,954**	175,924

[1] *See note 16 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 - September 30		Nine months ended - September 30	
USD Thousands	2022	2021	2022	2021
Net result	90,503	30,557	276,542	79,141
Net financial items	9,225	12,960	31,129	26,135
Income tax	37,977	11,988	102,927	16,276
Depletion	31,939	30,453	91,721	88,720
Depreciation of other tangible fixed assets	2,991	2,443	8,092	7,480
Exploration and business development costs	1,287	408	2,217	1,615
Depreciation included in general, administration and depreciation expenses[1]	406	414	1,201	1,300
EBITDA	**174,328**	89,223	**513,829**	220,667

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

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

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	2022	2021	2022	2021
Production costs	124,064	80,611	356,151	222,446
Cost of blending	(42,358)	(18,075)	(142,638)	(56,111)
Change in inventory position	(9,294)	671	4,434	16,952
Operating costs	**72,412**	63,207	**217,947**	183,287

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

USD Thousands	September 30, 2022	December 31, 2021
Bank loans	(11,874)	(113,122)
Bonds	(300,000)	–
Cash and cash equivalents	400,489	18,810
Net cash / (debt)	**88,615**	(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, 2021, IPC had a total of 155,342,757 common shares issued and outstanding.

Following the exercise of stock options during February 2021, the number of issued and outstanding common shares of the Corporation increased by 25,000 to 155,367,757 common shares.

On December 1, 2021, IPC announced the commencement of a normal course issuer bid / share repurchase program (NCIB). During the period up to December 31, 2021, IPC repurchased an aggregate of 1,330,303 common shares under the NCIB, of which 169,652 shares were cancelled at December 31, 2021. As at December 31, 2021, IPC had a total of 155,198,105 common shares issued and outstanding with voting rights.

As at June 30, 2022, following the cancellation during Q1 2022 of a further 4,232,092 common shares repurchased under the NCIB, IPC had a total of 150,966,013 common shares issued and outstanding with no par value.

During Q2 2022, the NCIB was temporarily suspended and IPC offered to repurchase common shares under the Substantial Issuer Bid (SIB). The SIB expired on June 28, 2022 and as at June 29, 2022, IPC had agreed to purchase an aggregate of 8,258,064 common shares under the SIB for a total amount of CAD 128 million. In early July 2022, such common shares were purchased and cancelled and IPC had a total of 142,707,949 common shares issued and outstanding.

IPC recommenced acquiring common shares under the NCIB following completion of the SIB. During the period of July to October 2022, IPC repurchased an aggregate of 4,865,088 common shares under the NCIB, all of which were cancelled. As at September 30, 2022, IPC had a total of 138,024,435 common shares issued and outstanding with voting rights, of which 12,344 common shares were held in treasury. As at November 1, 2022, IPC had a total of 137,842,861 common shares issued and outstanding with voting rights, with no common shares held in treasury.

Nemesia S.à.r.l., an investment company wholly owned by a Lundin family trust, owns 40,697,533 common shares in IPC, representing 29.5% of the outstanding common shares as at November 1, 2022.

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 5,123,058 IPC Share Unit Plan awards (10,703 awards granted in January 2020, 1,216,510 awards granted in March 2020, 25,335 awards granted in July 2020, 21,216 awards granted in January 2021, 675,138 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, 1,430,059 awards granted in March 2022 and 5,487 awards granted in July 2022) outstanding as at November 1, 2022.

Contractual Obligations and Commitments

In Canada, an oil pipeline from the Onion Lake Thermal field to the Husky Alberta Gathering System has been built by Husky Midstream ("Husky") 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 Husky 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:

	2022	2023	2024	2025	2026	Thereafter
Transportation service (MCAD)	6.8	27.3	28.0	28.4	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 has been provided for in the Group's Balance Sheet – see Note 16 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 460 thousand in respect of office space rental and USD 1,027 thousand in respect of shared services provided during the first nine months of 2022. Lundin Foundation has charged the Group USD 150 thousand in respect of sustainability advisory services provided to the Group during the first nine months of 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 September 30, 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 September 30, 2022, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 1, 2022 – December 31, 2022	16,000	WCS/WTI Differential	USD - 13.04/bbl

The above hedge is treated as effective and changes to the fair value are reflected in other comprehensive income. The hedge had a positive fair value of USD 12,124 thousand as at September 30, 2022.

In October 2022, IPC entered into a forward Western Canadian Select (WCS)/Argus WCS Houston (ARV) differential hedge for 12,000 bopd of its Canadian oil production in 2023 at USD 10.08 per barrel.

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.

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 is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2021 ("AIF") available on SEDAR at www.sedar.com or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward Looking Information" and "Reserves and Resource Advisory" in this MD&A.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in the AIF or 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 Covid-19 impacts 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 Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks 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 the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact of the pandemic.

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 nine month period ended September 30, 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.

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. Although demand, commodity prices and share prices have recovered, there can be no assurance that these effects will not resume or that commodity prices will not decrease or remain volatile in the future. 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. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

All statements other than statements of historical fact 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:

- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks;
- The potential for an improved future economic environment, including resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2022 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 ability to mitigate exposure to volatile WCS crude pride differentials;
- IPC's continued access to its credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures and share repurchases from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any future Covid-19 outbreaks 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 optimisation programs;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, 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 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 timing and success of the Villeperdue West development project 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 normal course issuer bid (NCIB), including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the substantial issuer bid (SIB) or the NCIB;
- The ability of IPC to implement future shareholder distributions in addition to the SIB and the NCIB;
- IPC's ability to implement its greenhouse gas ("GHG") emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- 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 and climate-related 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 free cash flow generation is based on IPC's current business plans over the period of 2022 to 2026. Assumptions include average net production of approximately 47 Mboepd, average Brent oil prices of USD 65 to 95 per boe escalating by 2% per year, average gas prices of CAD 3.00 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the AIF. 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 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 oil and gas assets. Gross reserves / resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves / resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of December 31, 2021, 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, 2021 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, 2021, 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, 2021 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the AIF. These price forecasts are as at December 31, 2021 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 270 MMboe as at December 31, 2021, by the mid-point of the 2022 CMD production guidance of 46,000 to 48,000 boepd.

The product types comprising the 2P reserves described in this MD&A are contained in the AIF. 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 chance of commerciality. In accordance with the COGE Handbook guidance for contingent resources, the chance of commerciality is solely based on the chance of development associated with resolution of all contingencies required for the re-classification of the contingent resources as reserves. Reported 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 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 the effects of aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves and contingent 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 reserve and resources evaluations will be attained and variances could be material.

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

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Supplemental Information regarding Product Types

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

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
September 30, 2022	22.7	10.4	101.5 MMcf (16.9 Mboe)	50.0
September 30, 2021	21.8	8.3	100.8 MMcf (16.7 Mboe)	46.8
Nine months ended				
September 30, 2022	22.6	9.4	98.1MMcf (16.4 Mboe)	48.4
September 30, 2021	20.0	8.4	99.6 MMcf (16.7 Mboe)	45.1
Year ended				
December 31, 2021	20.4	8.4	99.9 MMcf (16.7 Mboe)	45.5

This document also makes reference to IPC's forecast average daily production of 46,000 to 48,000 boepd for 2022. IPC estimates that approximately 46% of that production will be comprised of heavy oil, approximately 20% will be comprised of light and medium crude oil and approximately 34% 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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