Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2021

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt" 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 that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt 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 20.

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 25.

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, 2020, 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, 2020, 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, 2020, 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, 2020, 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, including the Corporation's common shares. Although demand, commodity prices and share prices have recovered in 2021, 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 2, 2021, 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, 2021 ("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 ("TSX") 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, 2021		September 30, 2020		December 31, 2020	
	Average	Period end	Average	Year end	Average	Year end
1 EUR equals USD	1.1967	1.1579	1.1241	1.1708	1.1413	1.2271
1 USD equals CAD	1.2515	1.2739	1.3538	1.3389	1.3412	1.2740
1 USD equals MYR	4.1296	4.1865	4.2346	4.1555	4.2026	4.0209

Q3 2021 HIGHLIGHTS

Business and Financial Highlights

- Average net production of approximately 46,800 barrels of oil equivalent (boe) per day (boepd) for the third quarter of 2021 is above the high end of the second quarter of 2021 guidance range for the period (46% heavy crude oil, 18% light and medium crude oil and 36% natural gas)[1].
- Full year 2021 average net production forecast increased to above 45,000 boepd[1] with an expected exit rate above 46,000 boepd.
- Production from the new sustaining Pad D' at Onion Lake Thermal, Canada successfully brought online in the third quarter of 2021, with initial performance ahead of expectations.
- Preparations continued during the quarter for the five well infill drilling campaign at Onion Lake Thermal and for the A15 sidetrack well at the Bertam Field, Malaysia.
- Operating costs[2] per boe of USD 14.7 for the third quarter of 2021, slightly better than Capital Market Day (CMD) guidance. No changes to full year guidance of USD 15.5 per boe.
- Record high operating cash flow (OCF)[2] generation for the third quarter and first nine months of 2021 amounted to MUSD 91 and MUSD 226 respectively.
- Full year OCF[2] guidance is increased to between MUSD 315 to MUSD 335 (actual realized prices for the first nine months of 2021 and Brent USD 75 to 85 per barrel for the fourth quarter of 2021) from MUSD 290 (Brent USD 75 per barrel).
- Capital and decommissioning expenditures of MUSD 30 for the first nine months of 2021. Full year guidance has been reduced to MUSD 50 from MUSD 73 following the re-phasing of drilling projects in Malaysia into the first quarter of 2022.
- Record high free cash flow (FCF)[2] generation for the third quarter and first nine months of 2021 amounted to MUSD 77 and MUSD 176 respectively.
- Full year FCF[2] guidance is increased to between MUSD 240 to MUSD 260 (actual realized prices for the first nine months of 2021 and Brent USD 75 to 85 per barrel for the fourth quarter of 2021) from MUSD 195 (Brent USD 75 per barrel).
- Forecast cumulative FCF[2] for 2021 to 2025 increased from approximately MUSD 600 to MUSD 1,200 to approximately MUSD 740 to MUSD 1,200 (Brent USD 55 to 75 per barrel) generating estimated average annual free cash flow yield over the five year period of between 17% and 28%[3].
- Net debt[2] of MUSD 161 as at September 30, 2021, down from MUSD 241 at the end of the second quarter of 2021 and down from MUSD 321 as at December 31, 2020.
- Net debt[2] to 12 month rolling EBITDA[2] ratio as at September 30, 2021 was 0.6 times.
- Net result of MUSD 31 for the third quarter of 2021.

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	2021	2020	2021	2020
Revenue	172,551	95,346	451,113	220,811
Gross profit / (loss)	58,636	5,557	130,852	(23,416)
Net result	30,557	8,850	79,141	(32,691)
Operating cash flow[2]	91,365	37,181	226,045	73,404
Free cash flow[2]	76,607	22,766	175,924	(19,229)
EBITDA[2]	89,223	34,251	220,667	65,447
Net Debt[2]	161,199	322,092	161,199	322,092

[1] See "Supplemental Information regarding Product Types" in the "Reserves and Resources Advisory" below.
[2] See definition on page 20 under "Non-IFRS measures".
[3] Free cash flow yield based on IPC market capitalization at October 29, 2021 (48.0 SEK/share, 8.6 SEK/USD, 868 MUSD). Assumptions described below in "Cautionary Statement Regarding Forward-Looking Information" on page 25.

Share Repurchase Program

- IPC intends to launch a new share repurchase program, the third since our April 2017 spin-off, with the intention to repurchase up to approximately 7% of IPC's outstanding common shares or 10.8 million IPC shares, the maximum permitted over a twelve month period under Canadian and Swedish securities law. Implementation of the share repurchase program remains subject to TSX approval.

OPERATIONS REVIEW

Business Overview

Market conditions for oil and gas producers have continued to strengthen during the third quarter of 2021. Third quarter 2021 average Brent oil prices were USD 73 per barrel, in excess of second quarter 2021 prices that averaged USD 69 per barrel.

Proactive supply management by the OPEC+ group, led by Saudi Arabia, is rebalancing the market. The International Energy Agency (IEA) is forecasting a net supply deficit during the fourth quarter of 2021 and excess oil inventory levels are reported to have drawn back down below pre-pandemic levels.

The recovery in oil demand remains on track as we see the easing of restrictions on mobility following the successful roll-out of Covid-19 vaccination programs to the wider population. With demand still not expected to fully recover to pre Covid-19 levels until next year, tapering of the supply curtailments by OPEC+ members looks set to continue into 2022.

In Canada, third quarter 2021 Western Canadian Select (WCS) crude price differentials averaged below USD 14 per barrel and forward markets into 2022 and 2023 are pricing the WCS differential at around USD 15 per barrel. Completion and placement into service of Enbridge's Line 3 replacement pipeline as well as the positive construction progress on the TransMountain pipeline expansion project is providing a much more constructive outlook for Canadian oil market egress relative to the tightness we have witnessed over the past several years. IPC has positioned itself well to benefit from this fundamental improvement in market conditions.

Gas markets have surged to new highs driven by a combination of increasing demand, lower supply and warmer than average temperatures that has diverted gas supply away from injecting into storage. Third quarter average Empress prices were above CAD 4.00 per Mcf and the winter strip pricing is above CAD 5.00 per Mcf. We could witness further tightness during the winter period if cold temperatures prevail.

IPC benefits from a well balanced mix of production comprising approximately 49% Canadian Crude, 36% Canadian Natural Gas and 15% Brent weighted oil.

With synchronized strength in pricing across the entire energy complex, combined with delivering operational excellence above the high end of our forecasts, IPC has been able to deliver our best ever quarterly financial performance since our launch in 2017 and has approved our third share repurchase program.

In addition we continue to remain opportunistic in our approach with respect to further M&A activity.

Third Quarter 2021 Highlights

During the third quarter of 2021, our assets delivered average net production of 46,800 boepd. Production for the first nine months of 2021 averaged 45,100 boepd.

This is our third quarter in succession of delivering production above our original high end guidance. It was made possible by the very high uptime performance across all our assets as well as the earlier than forecast production contribution from the newly commissioned Pad D' at Onion Lake Thermal.

In our second quarter report, we increased our full year average net daily production guidance to above 44,000 boepd with a forecast 2021 exit rate in excess of 45,000 boepd.

We now expect our full year average net daily production to be above 45,000 boepd with an increased forecast 2021 exit rate in excess of 46,000 boepd.

Our operating costs per boe for the third quarter of 2021 was USD 14.7, slightly better than our latest guidance. No changes are made to our full year guidance of USD 15.5 per boe.

Operating cash flow generation for the third quarter of 2021 was close to USD 91 million, a record high. First nine months' operating cash flow amounts to USD 226 million.

Full year operating cash flow guidance is now increased to between USD 315 million to USD 335 million (Brent USD 75 to 85 per barrel) from USD 290 million (Brent USD 75 per barrel).

Capital and decommissioning expenditures during the first nine months of 2021 was USD 30 million. Our full year 2021 guidance is reduced to USD 50 million from our second quarter guidance of USD 73 million. The reduction is largely the result of re-phasing Malaysian drilling expenditures into the first quarter of 2022.

Free cash flow generation was exceptionally strong at USD 77 million during the third quarter of 2021 and USD 176 million for the first nine months of 2021, a record high. This represents close to 22% of IPC's current market capitalization.

Full year 2021 free cash flow guidance is increased to between USD 240 million to USD 260 million (Brent USD 75 to 85 per barrel) from USD 195 million (Brent USD 75 per barrel). The revised guidance represents a free cash flow yield of between 28 to 30%.

A recent research report by RBC Capital Markets analyzing Global Integrated and E&P companies showed average 2021 free cash flow yields by each sub group to range between 8% and 16% with a global average of 12%. It is clear that IPC offers an attractive proposition for investors with a yield that is more than double that of our fellow industry peers.

We are revising our longer term guidance of generating between USD 600 and 1,200 million of free cash flow over the 2021 to 2025 period to between USD 740 and 1,200 million (with average Brent prices between USD 55 to 75 per barrel). This is to reflect our higher 2021 free cash flow. At this upper end of our forecast, the entire enterprise value of IPC would be liquidated in less than five years.

Net debt has reduced by half during the first nine months to USD 161 million. Net debt to EBITDA drops to 0.6 times from 3 times at the year-end 2020 (trailing 12 months), and deleveraging is continuing.

Share Repurchase Program

IPC is pleased to announce today that we have sought approval from the TSX to commence a normal course issuer bid (NCIB) to repurchase IPC's common shares through the facilities of the TSX and Nasdaq Stockholm. This will be IPC's third share repurchase program since listing in 2017. The Board of Directors has approved, subject to acceptance by the TSX, the repurchase of up to approximately 10.8 million common shares, representing approximately 7% of IPC's outstanding common shares (or 10% of IPC's "public float" as at November 2, 2021), over a period of twelve months. IPC currently does not hold any common shares in treasury.

As and when considered advisable by IPC, common shares may be repurchased on the TSX and Nasdaq Stockholm at the then prevailing market price at the time of such purchase, in accordance with the applicable rules and policies of the TSX and Nasdaq Stockholm and applicable Canadian and Swedish securities laws. The actual number of common shares that will be repurchased, and the timing of any such purchases, will be determined by IPC, subject to the limits imposed by the TSX and Nasdaq Stockholm. There cannot be any assurances as to the number of common shares that will ultimately be acquired by IPC. Any common shares purchased by IPC under the share repurchase program will be cancelled.

Environmental, Social and Governance ("ESG") Performance

Health, Safety & Environmental 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 2021, IPC recorded no material safety or environmental incidents.

In response to the Covid-19 pandemic, we remain focused on protecting the health and safety of our employees, contractors and other stakeholders, while also working to ensure business continuity. In the third quarter of 2021, IPC continued the health protocols implemented throughout the organization.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets are 272 MMboe as at December 31, 2020, as certified by independent third party reserves auditors. The reserves life index (RLI) as at December 31, 2020, is approximately 18 years. Best estimate contingent resources as at December 31, 2020, are 1,102 MMboe (unrisked). See "Reserves and Resources Advisory" below.

IPC initially set a limited capital budget for 2021, with the focus on free cash flow delivery to the business. At the end of the second quarter 2021, with strong production performance and improved market conditions strengthening free cash flow, IPC increased the capital expenditure budget to allow for infill drilling and optimisation projects in both Malaysia and Canada. The organic growth opportunities remain on schedule for execution by the end of 2021, with the exception of the Malaysia A15 sidetrack and Electric Submersible Pump (ESP) upsizing campaign being largely re-phased into the first quarter of 2022. IPC remains focused on free cash flow generation and, notwithstanding the inclusion of the incremental capital expenditure projects, IPC is on target for free cash flow delivery in excess of our original high end CMD guidance.

Production

The average net production during the third quarter of 2021 was 46,800 boepd. This is our third quarter in succession of delivering production above our high end CMD guidance. Exceptional production performance continued at the Canadian oil and gas assets. New production sustaining Pad D' at Onion Lake Thermal was brought online ahead of schedule and with initial production performance at the high end of forecast. In addition, strong performance from the Malaysian and French assets continued in Q3 2021 with excellent operational performance and facility uptime at the Bertam field in Malaysia and stable production performance in France with optimisation activity continuing to offset natural production declines. The planned maintenance shutdown at the Bertam field in Malaysia was successfully executed in Q3 2021.

With the continued strong production performance through Q3 2021, IPC now expects 2021 net average production to be in excess of 45,000 boepd, a nearly 1,000 boepd increase from our previous guidance of above 44,000 boepd. Average year to date net production as of the end Q3 2021 was 45,100 boepd. In addition, we now expect to exit 2021 with production in excess of 46,000 boepd.

The production during Q3 2021 with comparatives are summarized below:

Production in Mboepd	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
	2021	2020	2021	2020	2020
Crude oil					
Canada – Northern Assets	14.1	9.8	12.4	10.1	10.6
Canada – Southern Assets	8.7	7.2	8.7	6.7	7.1
Malaysia	4.2	4.4	4.3	4.5	4.4
France	3.0	3.1	3.0	2.8	2.8
Total crude oil production	**30.0**	24.5	**28.4**	24.1	24.9
Gas					
Canada – Northern Assets	0.1	0.1	0.1	0.1	0.1
Canada – Southern Assets	16.7	17.2	16.6	17.0	17.1
Total gas production	**16.8**	17.3	**16.7**	17.1	17.2
Total production	**46.8**	41.8	**45.1**	41.2	42.1
Quantity in MMboe	**4.31**	3.84	**12.30**	11.29	15.42

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

CANADA

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2021	2020	2021	2020	2020
- Oil Onion Lake Thermal	100%	11.5	9.1	10.2	9.1	9.5
- Oil Suffield	100%	7.6	6.0	7.6	5.4	5.9
- Oil Ferguson	100%	1.1	1.2	1.1	1.3	1.2
- Oil Other	50-100%	2.6	0.7	2.2	1.0	1.1
- Gas	99.7%[1]	16.8	17.3	16.7	17.1	17.2
Canada		**39.6**	34.3	**37.8**	33.9	34.9

[1] *On a well count basis*

Production
Net production from the Canadian assets during Q3 2021 was above the high end of CMD guidance at 39,600 boepd with continued strong performance and high production uptime at all the oil and gas producing assets. The new production sustaining Pad D' at Onion Lake Thermal delivered a strong quarter with production rates at the top end of forecast.

Organic Growth and Capital Projects
In Canada, IPC had originally set a limited capital budget for 2021. IPC continues to mature future development projects, with a significant portfolio of drilling and optimisation opportunities ready for sanction at the discretion of the Group. At the end of Q2 2021, IPC increased the capital expenditure budget to allow the 2021 execution of a five infill well project at the Onion Lake Thermal asset and an oil optimisation project at the Suffield asset.

At Onion Lake Thermal, the production sustaining Pad D' development project was completed ahead of schedule and in line with the approved budget. All six production wells have been brought online with positive initial results. During Q3 2021, the five well infill drilling campaign commenced at Onion Lake Thermal. Drilling operations are in line with schedule and on track to be completed in Q4 2021. A period of well steam conformance optimisation will be implemented during the planned phased production well start-up.

The production ramp up and testing of the third well pair at the Blackrod SAGD pilot project continued through Q3 2021. Heat conformance and production performance remain ahead of expectation.

MALAYSIA

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2021	2020	2021	2020	2020
Bertam	100%[1]	4.2	4.4	4.3	4.5	4.4

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

Production
Net production from the Bertam field on Block PM307 during Q3 2021 was ahead of CMD guidance at 4,200 boepd with continued excellent operational performance and facility uptime close to 100%. In Q3 2021, the Bertam field planned maintenance shutdown was successfully executed ahead of schedule and in line with the approved budget. Bertam FPSO produced water handling capacity has been increased from 17,000 to 24,000 barrels of water per day.

Organic Growth and Capital Projects
In Malaysia, IPC originally set a limited capital budget for 2021. At the end of Q2 2021, IPC increased the capital expenditure budget to allow for the planned 2021 execution of the A15 sidetrack well and the production well pump rate optimisation project.

At the end of Q3 2021, A15 sidetrack drilling operations have been re-scheduled to commence in late Q4 2021 with the production well pump rate optimisation project scheduled to follow in Q1 2022.

FRANCE

Production in Mboepd	WI	Three months ended - September 30		Nine months ended - September 30		Year ended December 31
		2021	2020	2021	2020	2020
- Paris Basin	100%[1]	2.6	2.7	2.6	2.3	2.4
- Aquitaine	50%	0.4	0.4	0.4	0.5	0.4
France		3.0	3.1	3.0	2.8	2.8

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

Production
Net production in France during Q3 2021 was ahead of CMD guidance at 3,000 boepd with stable production and good uptime at the major producing fields. In Q3 2021, strong reservoir performance continued at the Vert-la-Gravelle field supported by increased water injection.

Organic Growth
In France, IPC has set a limited capital budget for 2021. IPC continues to mature future development projects in France, with drilling and optimisation opportunities ready for sanction at the discretion of the Group.

FINANCIAL REVIEW

Financial Results

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q3-21	Q2-21	Q1-21	Q4-20	Q3-20	Q2-20	Q1-20	Q4-19
Revenue	**172,551**	144,278	134,284	103,353	95,346	44,929	80,536	145,535
Gross profit	**58,636**	34,286	37,930	(60,570)	5,557	(16,537)	(12,436)	43,245
Net result	**30,557**	21,693	26,891	(45,250)	8,850	(1,472)	(40,069)	38,372
Earnings per share – USD	**0.20**	0.14	0.17	(0.29)	0.06	(0.01)	(0.25)	0.23
Earnings per share fully diluted – USD	**0.19**	0.14	0.17	(0.29)	0.06	(0.01)	(0.25)	0.23
Operating cash flow[1]	**91,365**	66,959	67,721	46,019	37,181	14,742	21,481	78,888
Free cash flow[1]	**76,607**	50,366	48,951	28,571	22,766	717	(42,712)	4,432
EBITDA[1]	**89,223**	65,181	66,263	43,004	34,251	12,187	19,009	77,353
Net debt at period end[1]	**161,199**	240,617	286,132	321,193	322,092	341,367	302,473	231,503

[1] *See definition on page 20 under "Non-IFRS measures"*

Summarized interim consolidated balance sheet information is as follows:

USD Thousands	September 30, 2021	December 31, 2020
Non-current assets	1,163,507	1,240,653
Current assets	143,663	92,467
Total assets	**1,307,170**	1,333,120
Total non-current liabilities	421,106	527,530
Current liabilities	110,197	97,137
Total liabilities	**531,303**	624,667
Net assets	**775,867**	708,453
Working capital (including cash)	**33,466**	(4,670)

Segment 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, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	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**
Production costs (including inventory movements)	(33,198)	(30,993)	(7,450)	(8,970)	–	**(80,611)**
Depletion of oil and gas properties	(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**

	Three months ended – September 30, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	29,249	24,222	17,961	10,682	–	82,114
NGLs	–	54	–	–	–	54
Gas	86	14,367	–	–	–	14,453
Net sales of oil and gas	29,335	38,643	17,961	10,682	–	96,621
Change in under/over lift position	–	–	–	1,004	–	1,004
Royalties	(2,433)	(1,592)	–	–	–	(4,025)
Hedging settlement	(947)	(1,604)	–	–	–	(2,551)
Other operating revenue	–	–	3,910	327	60	4,297
Revenue	25,955	35,447	21,871	12,013	60	95,346
Production costs (including inventory movements)	(18,799)	(21,238)	(10,189)	(7,964)	–	(58,190)
Depletion of oil and gas properties	(6,283)	(10,532)	(6,902)	(4,814)	–	(28,531)
Depreciation of other assets	–	–	(2,906)	–	–	(2,906)
Exploration and business development costs	46	–	20	(136)	(92)	(162)
Gross profit/(loss)	919	6,677	1,894	(901)	(32)	5,557

[1] The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.

USD Thousands	Nine months ended – September 30, 2021					
	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	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**
Production costs (including inventory movements)	(95,115)	(93,018)	(5,259)	(29,054)	–	**(222,446)**
Depletion of oil and gas properties	(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**

USD Thousands	Nine months ended – September 30, 2020					
	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	57,371	49,794	41,896	25,367	–	174,428
NGLs	–	142	–	–	–	142
Gas	237	41,088	–	–	–	41,325
Net sales of oil and gas	57,608	91,024	41,896	25,367	–	215,895
Change in under/over lift position	–	–	–	(3,060)	–	(3,060)
Royalties	(5,248)	(3,266)	–	–	–	(8,514)
Hedging settlement	3,218	532	–	–	–	3,750
Other operating revenue	–	–	11,645	780	315	12,740
Revenue	55,578	88,290	53,541	23,087	315	220,811
Production costs (including inventory movements)	(48,034)	(64,653)	(15,990)	(18,729)	–	(147,406)
Depletion of oil and gas properties	(18,874)	(29,293)	(21,206)	(12,730)	–	(82,103)
Depreciation of other assets	–	–	(8,930)	–	–	(8,930)
Exploration and business development costs	(2,987)	–	88	(2,356)	(533)	(5,788)
Gross profit/(loss)	(14,317)	(5,656)	7,503	(10,728)	(218)	(23,416)

[1] The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.

Three and nine months ended September 30, 2021 Review

Revenue
Total revenue amounted to USD 172,551 thousand for Q3 2021, compared to USD 95,346 thousand for Q3 2020 and USD 451,113 thousand for the first nine months of 2021 compared to USD 220,811 thousand for the first nine months of 2020 and is analyzed as follows:

	Three months ended - September 30		Nine months ended - September 30	
USD Thousands	2021	2020	2021	2020
Crude oil sales	165,357	82,114	431,067	174,428
Gas and NGL sales	25,772	14,507	67,129	41,467
Change in under/overlift position	3,439	1,004	2,433	(3,060)
Royalties	(13,720)	(4,025)	(31,361)	(8,514)
Hedging settlement	(8,507)	(2,551)	(23,160)	3,750
Other operating revenue	210	4,297	5,005	12,740
Total revenue	**172,551**	95,346	**451,113**	220,811

The main components of total revenue for the three and nine months ended September 30, 2021, and September 30, 2020, respectively, are detailed below.

Crude oil sales

	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**

	Three months ended – September 30, 2020				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	29,249	24,222	17,961	10,682	82,114
- Quantity sold in bbls	1,019,326	755,941	394,291	265,552	2,435,110
- Average price realized USD per bbl	28.69	32.04	45.55	40.23	33.72

Crude oil revenue was more than double for Q3 2021 compared to Q3 2020 mainly due to higher oil prices. Q3 2020 was impacted by the global Covid-19 outbreak causing a decrease in oil demand and prices.

The Suffield area assets and part of the 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 2021, WTI averaged USD 71 per bbl compared to USD 41 per bbl for Q3 2020 and the average discount to WCS used in our pricing formula was USD 14 per bbl (USD 9 per bbl for Q3 2020).

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q3 2021 compared to two cargo liftings in Q3 2020. Produced unsold oil barrels from Bertam at the end of Q3 2021 amounted to 328,000 barrels, see Change in Inventory Position section below. There was no Aquitaine cargo lifted in Q3 2021. The average Dated Brent crude oil price was USD 73 per bbl for Q3 2021 compared to USD 43 per bbl for the comparative period.

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**

USD Thousands	Nine months ended – September 30, 2020 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	57,371	49,794	41,896	25,367	174,428
- Quantity sold in bbls	2,887,350	1,960,998	962,853	772,726	6,583,927
- Average price realized USD per bbl	19.87	25.39	43.51	32.83	26.49

Crude oil revenue was 147% higher for the first nine months of 2021 compared to the first nine months of 2020 mainly due to a 105% increase in achieved oil prices resulting from the improvement of market conditions as well as IPC's increased production.

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 2021, WTI averaged USD 65 per bbl compared to USD 39 per bbl for the comparative period and the average discount to WCS used in our pricing formula was USD 13 per bbl compared to USD 14 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 68 per bbl for the first nine months of 2021 compared to USD 41 per bbl for the comparative period.

Gas and NGL sales

	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**

	Three months ended – September 30, 2020 Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	14,421	86	14,507
- Quantity sold in Mcf	8,864,394	56,982	8,921,376
- Average price realized USD per Mcf	1.63	1.51	1.63

Gas and NGL sales revenue was 78% higher for Q3 2021 compared to Q3 2020 mainly due to the higher achieved gas price. Approximately 98% of the Suffield gas production was physically sold on the Alberta/Saskatchewan border with the remainder being delivered in Alberta based on AECO pricing plus a premium. For Q3 2021, IPC realized an average price of CAD 3.72 per Mcf compared to AECO average pricing of CAD 3.60 per Mcf and Empress average pricing of CAD 4.24 per Mcf for Q3 2021.

	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**

	Nine months ended – September 30, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	41,230	237	41,467
- Quantity sold in Mcf	26,191,218	170,180	26,361,398
- Average price realized USD per Mcf	1.57	1.39	1.57

Gas and NGL sales revenue was 62% higher for the first nine months of 2021 compared to the first nine months of 2020 mainly due to the higher achieved gas price. For the first nine months of 2021, IPC realized an average price of CAD 3.30 per Mcf compared to AECO average pricing of CAD 3.29 per Mcf and Empress average pricing of CAD 3.53 per Mcf for the first nine months of 2021.

Hedging settlement
IPC enters into risk management contracts in order to ensure a certain level of cashflow and to comply with covenants of its financing facilities. IPC's hedging strategy focuses mainly on oil price swaps and collars to limit pricing exposure. IPC also uses natural gas at the Onion Lake Thermal project and the Blackrod SAGD pilot project to generate steam and manages the pricing risk by entering into fixed price swaps. The oil and gas pricing contracts are not entered into for speculative purposes.

The realized hedging settlement for the first nine months of 2021 amounted to a loss of USD 23,160 thousand and consisted of a loss of USD 3,730 thousand on the gas contracts and a loss of USD 19,430 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 210 thousand for Q3 2021 compared to USD 4,297 thousand for Q3 2020 and USD 5,005 thousand for the first nine months of 2021 compared to USD 12,740 for the comparative period. Other operating revenue consists of lease fee income, tariff income and fees for strategic storage of inventory in France. The significant part of other operating revenue was 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 Carigli 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 80,611 thousand for Q3 2021 compared to USD 58,190 thousand for Q3 2020 and is analyzed as follows:

	Three months ended – September 30, 2021					
USD Thousands	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**

	Three months ended – September 30, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	17,640	14,205	20,280	7,132	(11,730)	47,527
USD/boe[2]	7.86	15.63	50.28	24.93	n/a	12.36
Cost of blending	3,488	4,251	–	–	–	7,739
Change in inventory position	110	343	1,639	832	–	2,924
Production costs	21,238	18,799	21,919	7,964	(11,730)	58,190

	Nine months ended – September 30, 2021					
USD Thousands	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**

	Nine months ended – September 30, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	43,440	54,687	53,531	18,042	(34,935)	134,765
USD/boe[2]	15.48	8.43	43.19	23.89	n/a	11.94
Cost of blending	4,251	9,657	–	–	–	13,908
Change in inventory position	343	309	(2,606)	687	–	(1,267)
Production costs	48,034	64,653	50,925	18,729	(34,935)	147,406

[1] See definition on page 20 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 cost per boe for Malaysia to USD 21.28 and USD 21.20 for Q3 2021 and Q3 2020 respectively and USD 17.83 and USD 15.00 for the nine months ended September 30, 2021, and September 30, 2020, respectively.

Operating costs
Operating costs amounted to USD 63,207 thousand for Q3 2021 compared to USD 47,527 thousand for Q3 2020 and USD 183,287 thousand for the first nine months of 2021 compared to USD 134,765 for the first nine months of 2020. Operating costs in Q3 2021 were higher than for Q3 2021 as energy costs in Q3 2021, both electricity and gas, were higher. Operating costs per boe amounted to USD 14.68 per boe in Q3 2021 below guidance, compared with USD 12.36 per boe in Q3 2020. Full year operating costs per boe guidance remains unchanged at USD 15.5 per boe due to expected higher energy costs in the fourth quarter of 2021.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Since July 2020, a portion of Onion Lake oil production is also blended and exported by pipeline. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 18,075 thousand for Q3 2021 compared to USD 7,739 thousand for Q3 2020 and USD 56,111 thousand for the first nine months of 2021 compared to USD 13,908 thousand for the first nine months of 2020. The increase is attributable to larger Onion Lake blending volumes and higher diluent prices in line with higher oil prices.

As a result of the blending, actual sales volumes are higher than produced barrels. A net gain of USD 277 thousand and a cost of USD 537 thousand were recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q3 2021 and Q3 2020 respectively. A gain of USD 207 thousand and a cost of USD 1,269 thousand were recognized for the first nine months ended September 30, 2021, and September 30, 2020, respectively.

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 2021, IPC had crude entitlement of 328,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold).

Depletion of oil and gas properties
The total depletion of oil and gas properties amounted to USD 30,453 thousand for Q3 2021 compared to USD 28,531 thousand for Q3 2020 and USD 88,720 thousand for the first nine months of 2021 compared to USD 82,103 thousand for the first nine months of 2020. The depletion charge is analyzed in the following tables:

	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**

	Three months ended – September 30, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,532	6,283	6,902	4,814	28,531
USD per boe	4.69	6.91	17.11	16.83	7.42

	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**

	Nine months ended – September 30, 2020				
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	29,293	18,874	21,206	12,730	82,103
USD per boe	4.52	6.73	17.11	16.85	7.27

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. The depletion rate for each field was updated for 2021 to align with the annual reserves report process at the end of 2020.

Depreciation of other assets
The total depreciation of other assets amounted to USD 2,443 thousand for Q3 2021 compared to USD 2,906 thousand for Q3 2020 and USD 7,480 thousand for the first nine months of 2021 compared to USD 8,930 thousand for the first nine months of 2020. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis over the 2P reserves of the Bertam field.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 408 thousand for Q3 2021 and USD 1,615 thousand for the first nine months of 2021. These costs mainly related to business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 3,131 thousand for Q3 2021 compared to USD 3,333 thousand for Q3 2020 and USD 9,300 thousand for the first nine months of 2021 compared to USD 9,328 thousand for the first nine months of 2020.

Net financial items
Net financial items amounted to a charge of USD 12,960 thousand for Q3 2021 compared to a credit of USD 1,033 thousand for Q3 2020 and a charge of USD 26,135 thousand for the first nine months of 2021 compared to a charge of USD 21,718 thousand for the first nine months of 2020, and included a largely non-cash net foreign exchange loss of USD 3,558 thousand for the first nine months of 2021 compared to a net foreign exchange loss of USD 1,616 thousand for the first nine months of 2020. The foreign exchange movements during the first nine months of 2021 are mainly resulting from the revaluation of intra-group funding loans.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 6,336 thousand for Q3 2021 compared to a charge of USD 6,843 thousand for Q3 2020 and a charge of USD 22,577 thousand for the first nine months of 2021 compared to a charge of USD 20,102 thousand for the first nine months of 2020.

The interest expense amounted to USD 2,664 thousand for Q3 2021 compared to USD 3,100 thousand for the comparative period in 2020 and USD 10,994 thousand for the first nine months of 2021 compared to USD 9,450 thousand for the first nine months of 2020. Despite the lower borrowings, the cost of financing was higher in the first nine months of 2021 compared to the first nine months of 2020 following the refinancing of the credit facilities in the summer of 2020. The cost of financing is expected to sigificantly reduce in the fourth quarter of 2021 and into 2022.

The unwinding of the asset retirement obligation discount rate amounted to USD 2,869 thousand for Q3 2021 compared to USD 2,747 thousand for Q3 2020 and USD 8,667 thousand for the first nine months of 2021 compared to USD 8,036 thousand for the first nine months of 2020.

Income tax
The corporate income tax amounted to a charge of USD 11,988 thousand for Q3 2021 compared to a credit of USD 5,593 thousand for Q3 2020 and a charge of USD 16,276 thousand for the first nine months of 2021 compared to a credit of USD 21,681 thousand for the first nine months of 2020. The income tax movements in the first nine months of 2021 mainly relate to deferred taxes with low cash taxes reflected. No corporate income tax is payable in Canada and Malaysia in 2021 due to the tax historic pools.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first nine months of 2021, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	9,829	13,170	2,976	1,453	27,428
Exploration and evaluation	–	(1,306)	420	7	(879)
	9,829	11,864	3,396	1,460	26,549

Capital expenditure of USD 26,549 thousand was mainly in Canada including completion of the Pad D' project and start of the infill drilling programme on the Onion Lake Thermal field, field optimisation activities and preparation for the drillling in Malaysia.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 49,676 thousand as at September 30, 2021, which included USD 46,785 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves.

Financial Position and Liquidity

Financing

As at January 1, 2020, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end of June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had a reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021, in connection with its oil and gas assets in Canada.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility") under a financial assistance program instituted by the French government. In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments commencing in August 2022. The France Facility amount was fully drawn as at September 30, 2021, and as at November 2, 2021.

In June 2020, the Group amended and extended the International RBL to a facility size of USD 125 million, with a maturity at the end of December 2024. In July 2020, the facility size was further increased to USD 140 million.

In March 2020, in connection with the completion of the acquisition of Granite Oil Corp. ("Granite"), the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility"). In July 2020, the Group amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended until the end of May 2022. In December 2020, the Granite Facility was amended to a CAD 30 million revolving credit facility.

In June 2021, the Group consolidated the amounts outstanding under the Granite Facility into the Canadian RBL and the Granite Facility was terminated. As of June 30, 2021, the Canadian RBL was amended to a facility size of CAD 300 million with a maturity extended until the end of May 2023. As of November 1, 2021, the Canadian RBL was amended to a facility size of CAD 250 million, with an unamended maturity of end May 2023. Under the Canadian RBL, the Group is required, and has satisfied the requirement, to hedge 40% of forecast Canadian oil production from June 30, 2021, to December 31, 2021. There are currently no mandatory hedging requirements beyond the end of 2021.

The borrowing base availability under the International RBL was agreed in June 2021 at USD 105 million of which USD 22 million was drawn as at September 30, 2021. The borrowing base availability under the Canadian RBL was CAD 300 million of which CAD 187 million was drawn as at September 30, 2021.

As at September 30, 2021, total net debt amounted to USD 161 million and the net debt to 12 month rolling EBITDA ratio was below 0.6 times.

The amounts drawn under the International RBL and the Canadian RBL as at September 30, 2021, are classified as non-current as there are no mandatory repayments within the next twelve months.

An amount of USD 965 thousand drawn under the France Facility as at September 30, 2021 is classified as current representing the repayment planned within the next twelve months.

The Group is in compliance with the covenants under the financing facilities as at September 30, 2021.

Cash and cash equivalents held amounted to USD 22,620 thousand as at September 30, 2021. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at September 30, 2021, the Group had a net working capital balance including cash of USD 33,466 thousand compared to USD (4,670) thousand as at December 31, 2020. The difference as at September 30, 2021, from December 31, 2020, is mainly as a result of higher trade receivables due to the higher oil price, the higher hydrocarbon stocks in Malaysia, the higher cash balances held and the reclassification of borrowings to long term following the refinancing in Canada, partly offet by the higher trade payables.

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", 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 less cash and cash equivalents.

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	2021	2020	2021	2020
Revenue	172,551	95,346	451,113	220,811
Production costs	(80,611)	(58,190)	(222,446)	(147,406)
Current tax	(575)	25	(2,622)	(1)
Operating cash flow	**91,365**	37,181	**226,045**	73,404

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	2021	2020	2021	2020
Operating cash flow - see above	91,365	37,181	226,045	73,404
Capital expenditures	(7,663)	(7,315)	(26,549)	(69,927)
Abandonment and farm-in expenditures[1]	(1,376)	(687)	(3,264)	(4,029)
General, administration and depreciation expenses before depreciation[2]	(2,717)	(2,905)	(8,000)	(7,958)
Cash financial items[3]	(3,002)	(3,508)	(12,308)	(10,719)
Free cash flow	**76,607**	22,766	**175,924**	(19,229)

[1] *See note 16 to the Financial Statements*
[2] *Depreciation is not specifically disclosed in the Financial Statements*
[3] *See notes 4 and 5 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	2021	2020	2021	2020
Net result	30,557	8,850	79,141	(32,691)
Net financial items	12,960	(1,033)	26,135	21,718
Income tax	11,988	(5,593)	16,276	(21,681)
Depletion of oil and gas properties	30,453	28,531	88,720	82,103
Depreciation of other assets	2,443	2,906	7,480	8,930
Exploration and business development costs	408	162	1,615	5,788
Depreciation included in general, administration and depreciation expenses[1]	414	428	1,300	1,280
EBITDA	**89,223**	34,251	**220,667**	65,447

[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	2021	2020	2021	2020
Production costs	80,611	58,190	222,446	147,406
Cost of blending[1]	(18,075)	(7,739)	(56,111)	(13,908)
Change in inventory position	671	(2,924)	16,952	1,267
Operating costs	**63,207**	47,527	**183,287**	134,765

[1] *Item is shown in the Financial Statements. See production costs section above.*

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

USD Thousands	September 30, 2021	December 31, 2020
Bank loans	183,819	327,691
Cash and cash equivalents	(22,620)	(6,498)
Net debt	**161,199**	321,193

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued two letters of credit as follows: (a) CAD 2.6 million in respect of its obligations to purchase diluent; and (b) CAD 600,000 in respect of its obligations related to the Ferguson asset, increasing by CAD 100,000 annually to a maximum of CAD 1,000,000.

IPC has also guaranteed the obligations of its subsidiary, IPC Canada Ltd, in respect of its pipeline gathering and transportation of crude oil for a maximum amount of CAD 3.6 million and its electricity supply for a maximum amount of CAD 1.0 million.

Outstanding Share Data

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

As at January 1, 2020, the total number of common shares issued and outstanding in IPC was 159,790,869. In 2020, IPC repurchased 4,448,112 common shares under a share repurchase program and all of these shares were cancelled. IPC suspended further share repurchases under the program which expired in early November 2020. As at December 31, 2020, 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 has increased by 25,000 to 155,367,757 common shares. As at September 30, 2021, and as at November 2, 2021, IPC had a total of 155,367,757 common shares issued and outstanding with voting rights.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 26.2% of the outstanding common shares as at November 2, 2021.

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 5,463,001 IPC Share Unit Plan awards (81,851 awards granted in March 2019, 1,037,981 awards granted in July 2019, 10,703 awards granted in January 2020, 1,490,410 awards granted in March 2020, 25,335 awards granted in July 2020, 45,781 awards granted in January 2021, 1,036,773 awards granted in March 2021, 1,716,000 awards granted in May 2021 and 18,167 awards granted in July 2021) outstanding as at November 2, 2021.

Contractual Obligations and Commitments

IPC has an obligation to make payments towards historic costs on Block PM307 in Malaysia 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 to the Financial Statements.

The Bertam field has leased the FPSO Bertam from another Group company for a period up to April 2022, with three further one-year options to extend such lease up to April 2025.

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

Lundin Energy has charged the Group USD 480 thousand in respect of office space rental and USD 1,040 thousand in respect of shared services provided during the first nine months of 2021.

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, 2021, 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 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 gas price sale financial hedges outstanding as at September 30, 2021, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
October 1, 2021 - December 31,2021	21,667	AECO Swap	CAD 3.24/GJ
January 1, 2022 - March 31, 2022	20,000	AECO Swap	CAD 4.15/GJ
April 1, 2022 - September 30, 2022	20,000	AECO Swap	CAD 3.14/GJ

The Group had oil price sale financial hedges outstanding as at September 30, 2021, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 1, 2021 - December 31, 2021	5,000	WCS Swap	USD 44.16/bbl
October 1, 2021 – December 31, 2021	3,300	WTI Collar	USD 57.94/bbl - 77.26/bbl
October 1, 2021 - December 31, 2021	3,300	WCS/WTI Differential	USD -13.94/bbl

All of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

These hedges had a net negative fair value of USD 13,486 thousand as at September 30, 2021.

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.

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, 2020 ("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 a reduction in demand for oil and gas consumption and/or lower commodity prices and/or reliance on third parties. 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 the current and any future 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.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

There have been no material changes to the Groups internal control over financial reporting during the three month period ended September 30, 2021, 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, including the Corporation's common shares. Although demand, commodity prices and share prices have recovered in 2021, 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 may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

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

- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks and reductions in commodity prices;
- The potential for an improved economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2021 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 low or volatile commodity prices;
- IPC's ability, as market conditions evolve and if determined necessary from time to time, to reduce expenditures and curtail production, and then to resume such production;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund future expenditures from cash flows and current borrowing capacity;
- IPC's ability to maintain operations, production and business in light of the current and any 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 optimization programs;
- Development of the Blackrod project in Canada;
- Current and future drilling pad production and timing and success of facility upgrades, tie-in work and infill drilling at Onion Lake Thermal, Canada;
- The ability to maintain current and forecast production in France;
- The ability of IPC to continue transportation arrangements for Paris Basin production following the closure of the Total-operated Grandpuits refinery, including at costs estimated by the Corporation;
- The ability to maintain current and forecast production in Malaysia;
- The timing and success of the drilling of the A15 sidetrack well and of the production well pump rate optimisation project in Malaysia;
- The intention to commence a share repurchase program, including the acceptance thereof by the TSX;
- The ability to IPC to acquire common shares under the proposed share repurchase program, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the share repurchase program;
- The ability of IPC to implement further shareholder distributions in addition to the share repurchase program;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt; and
- Future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:

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

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

Estimated free cash flow generation is based on IPC's current business plans over the period of 2021 to 2025. Assumptions include average net production of approximately 45 Mboepd, average Brent oil prices of USD 55 to 75 per boe escalating by 2% per year, average gas prices of CAD 2.50 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, 2020, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") 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 RESOURCE 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, 2020, 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, 2020, 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, 2020, 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, 2020, 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.

The reserve life index ("RLI") is calculated by dividing the 2P reserves of 272 MMboe as at December 31, 2020, by the midpoint of the initial 2021 average net daily production guidance of 41,000 to 43,000 boepd.

The product types comprising the 2P reserves and the contingent resources 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 being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

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

The contingent resources reported in the 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 aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

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

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 (Mboepd)	Light and Medium Crude Oil (Mboepd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
September 30, 2021	21.8	8.3	100.8 Mcf (16.7 Mboe)	46.8
September 30, 2020	15.8	8.7	103.8 Mcf (17.3 Mboe)	41.8
Nine months ended				
September 30, 2021	20.0	8.4	99.6 Mcf (16.7 Mboe)	45.1
September 30, 2020	15.6	8.5	102.6 Mcf (17.1 Mboe)	41.2
Year ended				
December 31, 2020	16.5	8.5	103.1 Mcf (17.2 Mboe)	42.1

This document also makes reference to IPC's forecast average net daily production of above 45,000 boepd for 2021. IPC estimates that approximately 45% of that production will be comprised of heavy oil, approximately 18% will be comprised of light and medium crude oil and approximately 37% 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
ASP	Alkaline surfactant polymer (an EOR process)
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
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 B ritish thermal units
Mcf	Thousand 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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