Q4

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2020

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”/”net cash” which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See “Non-IFRS Measures” on page 23.

Forward-Looking Statements

Certain statements contained in this MD&A constitute “forward-looking statements” or “forward-looking information” (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", “forecast”, "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the “Cautionary Statement Regarding Forward-Looking Information” on page 35.

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 have had a drastic adverse 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. There can be no assurance that these adverse effects will not continue 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 February 9, 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 audited consolidated financial statements and accompanying notes for the year ended December 31, 2020 ("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:

	December 31, 2020		December 31, 2019	
	Average	Period end	Average	Year end
1 EUR equals USD	1.1413	1.2271	1.1196	1.1234
1 USD equals CAD	1.3412	1.2740	1.3270	1.2994
1 USD equals MYR	4.2026	4.0209	4.1422	4.0905

HIGHLIGHTS

2020 Operational and Resource and 2021 Business Plan Highlights

- Average net production of approximately 44,900 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2020 (43% heavy crude oil, 18% light and medium crude oil and 39% natural gas)[1].
- Full year 2020 average net production of approximately 42,100 boepd, in line with Q3 2020 guidance (39% heavy crude oil, 20% light and medium crude oil and 41% natural gas)[1].
- Full year 2020 operating costs[2] per boe of USD 11.9, in line with Q3 2020 guidance.
- Capital expenditure for full year 2020 of USD 82 million, marginally above Q3 2020 guidance after the decision to advance work at Onion Lake Thermal, Canada.
- Completed the acquisition of Granite Oil Corp. (Granite) in Q1 2020, adding the Ferguson light oil asset to IPC's Canadian business.
- First IPC Sustainability Report published in Q3 2020.
- Proved plus probable (2P) reserves as at December 31, 2020 of 272 million boe (MMboe), with a reserves life index (RLI) of 18 years[1].
- Contingent resources (best estimate, unrisked) as at December 31, 2020 of 1,102 MMboe[1].
- 2021 average net production guidance of 41,000 to 43,000 boepd.[1]
- 2021 operating costs guidance[2] at USD 14.6 per boe.
- Full year 2021 capital expenditure budget of USD 37 million, with a focus in 2021 on free cash flow generation and debt reduction.
- Forecast cumulative free cash flow[2] for 2021 to 2025 of approximately USD 600 million to USD 900 million, generating estimated average annual free cash flow yield over the five year period of between 28% and 42%.[3]

[1] See "Supplemental Information regarding Product Types" in the "Reserves and Resources Advisory" below and the Corporation's material change report dated February 9, 2021 (MCR), available on the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

[2] See definition on page 23 under "Non-IFRS measures".

[3] 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 over that period of approximately 45 Mboepd, average Brent oil prices of USD 55 to 65 per boe escalating by 2% per year, average gas prices of CAD 2.50 per Mcf, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the MCR. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts. See "Cautionary Statement regarding Forward-Looking Information" below. Free cash flow yield is based on IPC's market capitalization at close February 5, 2021 (23.36 SEK/share, 8.4 SEK/USD, USD 433 million).

2020 Financial Highlights

	Three months ended December 31		Year ended December 31	
USD Thousands	2020	2019	2020	2019
Revenue	103,353	145,535	324,164	553,749
Gross profit / (loss)	(60,570)	43,245	(83,986)	152,904
Net result	(45,250)	38,372	(77,941)	103,588
Operating cash flow[1]	46,019	78,888	119,423	307,944
Free cash flow[1]	28,571	4,432	9,342	89,308
EBITDA[1]	43,004	77,353	108,451	302,513
Net Debt[1]	321,193	231,503	321,193	231,503

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

- Full year 2020 operating cash flow (OCF)[1] of USD 119 million and USD 46 million for the fourth quarter 2020.
- Full year 2020 free cash flow (FCF)[1] generation of USD 9 million and USD 29 million for the fourth quarter 2020.
- Net debt[1] of USD 321 million as at December 31, 2020.
- Net debt[1] to EBITDA[1] ratio of 2.96 times as at December 31, 2020.
- Full year 2020 net result of USD (78 million) and USD (45 million) for the fourth quarter 2020 including a non-cash impairment charge of USD 54 million after tax on the French Paris Basin assets.

OPERATIONS REVIEW

Business Overview

2020 was certainly the year when we were all called upon to rise up and face the unprecedented challenge of dealing with the outbreak of the Covid-19 pandemic effects. The restrictions we all had to endure to combat the virus in early 2020 turned our world upside down, leading to a collapse in oil demand and profound oil price weakness. The lack of an early agreement by OPEC+ on a supply response only served to exacerbate market balances which had already become severely dislocated.

Thankfully though, following agreement on the deepest production curtailments we have ever seen from the OPEC+ group and other producers, including ourselves, we began to see some positive results. Those actions managed to flatten the curve of inventory builds towards the end of the second quarter of 2020. This in turn led to the oil market moving into deficit during the second half of 2020 with a draw down in excessive inventory levels as the rebalancing process commenced. As a result of the market tightening, average Brent oil prices increased from second quarter levels of around USD 30 per barrel to around USD 45 per barrel during the fourth quarter.

As we look forward into 2021, uncertainties remain as we continue to see new variants and waves of Covid-19 infections. The pace of recovery in oil demand will be dependent on the successful roll out of the vaccination program and the easing of restrictions on mobility. For a sustained recovery in oil prices, discipline and compliance on the supply side measures announced by OPEC+ will also be essential, particularly when considering the timing of easing of the supply curtailments.

As a result, we believe it is prudent to exercise caution with respect to future capital expenditure and growth plans. We held firm on our reset 2020 expenditure program even as we saw oil prices recovering in the second half of the year. We have set a limited capital budget for 2021 with a focus on free cash flow generation and debt reduction. We do not expect to see a return to organic production growth until we see stronger evidence of a more balanced market.

That being said, the massive collapse in investment combined with the redirection of future capital investment away from upstream oil and gas in favour of renewable energy by the majors, along with the dramatic reductions in US shale drilling activity, could set the scene for brighter times ahead. IPC believes that we are very well positioned to benefit from the recovery.

We expect to continue with our opportunistic approach with respect to further business development opportunities. Despite the turmoil the sector has been through, we have already witnessed an uptick in activity levels in the Mergers and Acquisitions ("M&A") market and anticipate that this will continue in the months ahead.

Update of 2020 Business Plan

Given that IPC operates the majority of our assets, during the first half of 2020 we had the financial and operational flexibility to react swiftly to the situation and to positively position the Corporation to navigate through the period of low commodity prices. All discretionary 2020 expenditures were deferred or cancelled. In addition, during the second quarter of 2020, we took the decision to temporarily curtail production from fields that were not expected to generate positive cash flows at the low pricing levels we were experiencing. These production curtailments related to a portion of our oil production. Our Canadian gas production was not curtailed as we continued to generate strong positive cash flows.

With the improvement in our business outlook, and in particular the strengthening of Canadian crude oil prices, we took the decision in late Q2 2020, to progressively bring back on stream our oil production from our Suffield Oil asset and our Onion Lake Thermal asset. In addition, production from our Paris Basin assets in France had returned to pre-curtailment levels by June 2020.

During the second half of 2020, the recovery of our Canadian oil production was running ahead of forecast and, by Q3 2020, we guided that we expected production for the full year 2020 to be in excess of our high end guidance range of 37,000 to 40,000 boepd at above 41,000 boepd. We are pleased to report that our production recovery continued during the fourth quarter resulting in our full year net production averaging in excess of 42,000 boepd. A particular achievement of our operating teams across all our sites was the fact that none of our assets faced any interruption as a result of the Covid-19 outbreak during 2020.

IPC's 2020 capital and decommissioning expenditures of USD 82 million were marginally above our Q3 guidance by USD 2 million as we elected to accelerate Onion Lake Thermal Pad D' project works into a more favourable weather window. IPC's 2020 unit operating costs of USD 12 per boe came in at the lower end of our guidance range of USD 12 to 13 per boe.

Our full year operating cash flow amounted to USD 119 million. Notwithstanding the market turmoil, we were able to generate a positive free cash flow of approximately USD 9 million during 2020 as a result of the business reset measures we put in place.

Fourth Quarter 2020 Performance

During the fourth quarter of 2020, our assets delivered average net production of 44,900 boepd, a 7% increase over our Q3 2020 production levels as we continued with the ramp up of the majority of our curtailed oil production in Canada. Our operating costs per boe for the fourth quarter of 2020 was USD 11.9, at the low end of our guidance range.

Operating cash flow generation for the fourth quarter of 2020 amounted to USD 46.0 million, stronger than forecast as a result of stronger oil prices and better than forecast production. Moreover, as a result of our spending reductions, operational choices made and our hedging program, IPC generated USD 29 million of free cash flow during the fourth quarter of 2020.

Capital and decommissioning expenditures during the fourth quarter of 2020 of USD 9.2 million was marginally above forecast following the decision to advance work on Onion Lake Thermal. The limited level of expenditure in Q4 2020 reflects the implementation of our expenditure reduction program previously announced.

Net debt as at December 31, 2020 was USD 321 million.

Maximizing Financial Flexibility

During the first quarter of 2020, we generated in excess of USD 40 million of negative free cash flow as we commenced our front-end loaded investment program that was aimed at growing our production. Given the collapse in oil prices late in Q1 2020, it was clear that our original growth program was not going to be sustainable. As a result, our business reset plan was put in place aimed at maximizing our free cash flow generation to navigate through the weak oil price environment. In Q2 2020, we already delivered free cash flow neutrality and moreover, in the second half of 2020 we were able to generate in excess of USD 50 million of positive free cash flow. For the full year 2020, our reset program delivered what it set out to achieve with IPC generating a USD 9 million free cash flow surplus.

In parallel to our business reset, it was also very important to ensure that we had continued access to our banking facilities. In early Q3 2020, we were pleased to report that we had successfully concluded our discussions with our Canadian and international banking partners. Maturities of our credit facilities were extended and in total we were able to increase the size of these available credit facilities by more than USD 10 million whilst removing any leverage ratio covenants.

As we move into 2021, the focus on free cash flow generation and debt reductions continues with a minimal capital budget proposed that is expected to allow us to sustain production at around our average 2020 levels and achieve our 2021 production guidance.

HSE 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 2020, IPC recorded no material safety or environmental incidents.

In response to the Covid-19 outbreak, we remain focused on protecting the health and safety of our employees, contractors and other stakeholders, while also working to ensure business continuity. Throughout 2020, IPC implemented and continued the health protocols throughout the organization.

Sustainability Reporting

Responsible operatorship and ensuring that we adhere to the highest principles of business conduct have been an integral part of how we do business since the creation of IPC in 2017. Over the past three years, IPC has rapidly grown our business with the completion of three acquisitions in Canada as well as significant investments in our French and Malaysian businesses.

In parallel, we have made a concerted effort to further develop and improve our sustainability strategy. An important part of this journey involves the measurement and transparent reporting of a broad range of ESG metrics. Alongside the publication of our third quarter 2020 report, we were very pleased to publish our inaugural Sustainability Report. We encourage everyone to read it and see first-hand the good work that is being done within our company.

As previously announced, IPC targets a reduction of our net GHG emissions intensity by the end of 2025 to 50% of the Corporation's 2019 baseline.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets stand at 272 MMboe as at December 31, 2020, 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 remains focused on organic growth, continuing to mature and high grade opportunities across all our operated assets in 2021. Following the decision to ramp up curtailed oil production in Canada in response to stronger commodity pricing through the second half of 2020, our production increases were ahead of our forecast. IPC continues to review all deferred operational and development activities to identify and prioritise those which generate positive returns at current pricing levels whilst preserving strong free cash flow generation. Ensuring health and safety of our employees, contractors and other stakeholders, remains a top priority.

Production

The average net production during the fourth quarter of 2020 exceeded revised guidance at 44,900 boepd, driven by strong reservoir performance and well optimisation at the Suffield assets in addition to the continued ramp up at Onion Lake Thermal in Canada. Exceptional operational performance and facility uptime was achieved at the Bertam field in Malaysia and France delivered stable low-decline production, in line with guidance expectations.

As a result of the strong production performance in the second half of 2020, IPC delivered a full year 2020 net average production in excess of 42,000 boepd and an exit rate in excess of 44,000 boepd.

The production during Q4 2020 with comparatives are summarized below:

Production in Mboepd	Three months ended December 31		Year ended December 31	
	2020	2019	**2020**	2019
Crude oil				
Canada – Northern Assets	12.0	14.0	10.6	13.1
Canada – Southern Assets	8.4	6.5	7.1	6.4
Malaysia	4.2	5.4	4.4	5.8
France	2.9	3.2	2.8	2.5
Total crude oil production	**27.5**	29.1	**24.9**	27.8
Gas				
Canada – Northern Assets	0.1	0.1	0.1	0.1
Canada – Southern Assets	17.3	18.0	17.1	17.9
Total gas production	**17.4**	18.1	**17.2**	18.0
Total production	**44.9**	47.2	**42.1**	45.8
Quantity in MMboe	**4.13**	4.34	**15.42**	16.72

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

CANADA

Production in Mboepd	WI	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
- Oil Onion Lake Thermal	100%	10.6	11.4	9.5	10.2
- Oil Suffield	100%	7.2	6.5	5.9	6.4
- Oil Ferguson	100%	1.2	–	1.2	–
- Oil Other	50 - 100%	1.4	2.6	1.1	2.9
- Gas	99.7%[1]	17.4	18.1	17.2	18.0
Canada		**37.8**	38.6	**34.9**	37.5

[1] *On a well count basis.*

Production
Net production from the Canadian assets during Q4 2020 was ahead of revised guidance at 37,800 boepd. Strong production performance continued at the Suffield assets, underpinned by base well rate optimisation and ahead of expectation production recovery at the N2N Enhanced Oil Recovery ASP (Alkaline Surfactant Polymer) project. 10,720 wells were swabbed during 2020 at the Suffield Gas properties, with the aim of offsetting natural declines. At Blackrod, oil production ramp up progressed in Q4 2020, with promising initial conformance and production results from the third well pair in the SAGD (Steam Assisted Gravity Drainage) pilot project. At Onion Lake Thermal, production rates returned to near pre-curtailment levels with excellent reservoir management and steam allocation.

Organic Growth and Capital Projects
In Canada, IPC originally forecasted a comprehensive expenditure plan including multiple drilling programs and project work as part of the operational and capital budgets for 2020. As part of the business reset by IPC in early 2020, non-committed and discretionary expenditures were restricted, deferred and cancelled for 2020. IPC continues to review future development expenditure projects and plans a limited capital expenditure budget for 2021.

At Onion Lake Thermal, during Q4 2020, the Pad D' facilities work was completed in a more favorable weather window, contributing to a marginal increase to the Q3 2020 capital guidance. As of the end of Q4 2020, all five production wells and fourteen production supporting steam injection wells have been drilled for the Pad D' project. Well completions, facility upgrades and tie-in works are scheduled to be completed in 2021.

During Q3 2020, following an extensive production well heat conformance optimisation period, the third well pair at the Blackrod SAGD pilot project was converted to oil production and successfully brought online. Steam conformance optimisation, production ramp up and well performance testing is ahead of expectation and scheduled to continue through 2021.

MALAYSIA

Production in Mboepd	WI	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Bertam	75%	**4.2**	5.4	**4.4**	5.8

Production
Net production from the Bertam field on Block PM307 during Q4 2020 was ahead of revised guidance at 4,200 boepd with excellent operational performance and facility uptime close to 100% at FPSO Bertam.

Petronas Carigali Sdn Bhd, the holder of a 25% WI in Block PM307, has notified IPC of its withdrawal from the Block effective as of April 2021. IPC will increase its WI from 75% to 100% as of such date.

Organic Growth and Capital Projects
During 2020, IPC suspended further development activity in Malaysia and will continue to review future capital expenditure projects in light of the commodity price environment.

FRANCE

Production in Mboepd	WI	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
France					
- Paris Basin	100%[1]	2.5	2.7	2.4	2.0
- Aquitaine	50%	0.4	0.5	0.4	0.5
		2.9	3.2	**2.8**	2.5

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

Production
Net production in France during Q4 2020 was in line with revised guidance at 2,900 boepd with steady production performance at all the major producing fields.

IPC currently delivers oil production from its Paris Basin assets for sale at the Total-operated Grandpuits refinery under a contract with Total until December 31, 2021. In Q3 2020, Total announced it will discontinue crude oil refining in the first quarter of 2021. IPC continues maturing alternative transport and marketing solutions that were implemented during previous periods of downtime at the refinery. IPC currently expects the new transportation solutions to increase the net operating costs by around USD 5 per bbl.

Organic Growth
During 2020, IPC suspended further development activity in France and will continue to review future capital expenditure projects in light of the commodity price environment.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	2020	2019	2018
Revenue	324,164	553,749	454,443
Gross profit	(83,986)	152,904	146,864
Net result	(77,941)	103,588	103,644
Earnings per share – USD	(0.50)	0.63	1.13
Earnings per share fully diluted – USD	(0.49)	0.62	1.12
Operating cash flow[1]	119,423	307,944	279,018
EBITDA[1]	108,451	302,513	264,041
Net debt at period end[1]	321,193	231,503	276,761

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2020	December 31, 2019	December 31, 2018
Non-current assets	1,240,653	1,252,600	1,200,035
Current assets	92,467	112,041	98,899
Total assets	1,333,120	1,364,641	1,298,934
Total non-current liabilities	527,530	474,200	506,832
Current liabilities	97,137	99,632	96,315
Total liabilities	624,667	573,832	587,296
Net assets	708,453	790,809	695,787
Working capital (including cash)	(4,670)	12,409	2,584

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2020	Q4-20	Q3-20	Q2-20	Q1-20	2019	Q4-19	Q3-19	Q2-19	Q1-19
Revenue	324,164	103,353	95,346	44,929	80,536	553,749	145,535	131.437	129,357	147,420
Gross profit	(83,986)	(60,570)	5,557	(16,537)	(12,436)	152,904	43,245	23,487	39,287	46,885
Net result	(77,941)	(45,250)	8,850	(1,472)	(40,069)	103,588	38,372	6,330	25,744	33,142
Earnings per share – USD	(0.50)	(0.29)	0.06	(0.01)	(0.25)	0.63	0.23	0.04	0.16	0.20
Earnings per share fully diluted – USD	(0.49)	(0.29)	0.06	(0.01)	(0.25)	0.62	0.23	0.04	0.15	0.20
Operating cash flow[1]	119,423	46,019	37,181	14,742	21,481	307,944	78,888	69,504	76,496	83,056
EBITDA[1]	108,451	43,004	34,251	12,187	19,009	302,513	77,353	68,885	74,600	81,675
Net debt at period end[1]	321,193	321,193	322,092	341,367	302,473	231,503	231,503	207,778	239,322	256,962

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

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 – December 31, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	31,835	28,352	18,569	10,333	–	**89,089**
NGLs	–	72	–	–	–	**72**
Gas	97	18,528	–	–	–	**18,625**
Net sales of oil and gas	**31,932**	**46,952**	**18,569**	**10,333**	**–**	**107,786**
Change in under/over lift position	–	–	–	2,430	–	**2,430**
Royalties	(2,954)	(2,596)	–	–	–	**(5,550)**
Hedging settlement	(1,867)	(3,866)	–	–	–	**(5,733)**
Other operating revenue	–	–	3,910	384	126	**4,420**
Revenue	**27,111**	**40,490**	**22,479**	**13,147**	**126**	**103,353**
Production costs (including inventory movements)	(16,589)	(24,106)	(8,803)	(7,724)	–	**(57,222)**
Depletion	(7,381)	(11,262)	(6,553)	(4,597)	–	**(29,793)**
Depreciation of other assets	–	–	(2,751)	–	–	**(2,751)**
Exploration and business development costs	(24)	–	(829)	(33)	(128)	**(1,014)**
Impairment costs of oil and gas properties	–	–	–	(73,143)	–	**(73,143)**
Gross profit/(loss)	**3,117**	**5,122**	**3,543**	**(72,350)**	**(2)**	**(60,570)**

	Three months ended – December 31, 2019					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	43,791	27,950	36,618	16,167	–	124,526
NGLs	–	79	–	–	–	79
Gas	122	19,335	–	–	–	19,457
Net sales of oil and gas	43,913	47,364	36,618	16,167	–	144,062
Change in under/over lift position	–	–	–	3,030	–	3,030
Royalties	(4,662)	(1,838)	–	–	–	(6,500)
Hedging settlement	523	–	–	–	–	523
Other operating revenue	–	–	3,910	301	209	4,420
Revenue	39,774	45,526	40,528	19,498	209	145,535
Production costs (including inventory movements)	(19,194)	(25,252)	(12,286)	(8,590)	–	(65,322)
Depletion	(8,283)	(12,560)	(7,034)	(4,581)	–	(32,458)
Depreciation of other assets	–	–	(3,805)	–	–	(3,805)
Exploration and business development costs	–	–	(262)	–	(443)	(705)
Gross profit/(loss)	12,297	7,714	17,141	6,327	(234)	43,245

	Year ended – December 31, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	89,206	78,146	60,465	35,700	–	**263,517**
NGLs	–	214	–	–	–	**214**
Gas	334	59,616	–	–	–	**59,950**
Net sales of oil and gas	**89,540**	**137,976**	**60,465**	**35,700**	**–**	**323,681**
Change in under/over lift position	–	–	–	(630)	–	**(630)**
Royalties	(8,202)	(5,862)	–	–	–	**(14,064)**
Hedging settlement	1,351	(3,334)	–	–	–	**(1,983)**
Other operating revenue	–	–	15,555	1,164	441	**17,160**
Revenue	**82,689**	**128,780**	**76,020**	**36,234**	**441**	**324,164**
Production costs (including inventory movements)	(64,623)	(88,759)	(24,793)	(26,453)	–	**(204,628)**
Depletion	(26,255)	(40,555)	(27,759)	(17,327)	–	**(111,896)**
Depreciation of other assets	–	–	(11,681)	–	–	**(11,681)**
Exploration and business development costs	(3,011)	–	(741)	(2,389)	(661)	**(6,802)**
Impairment costs of oil and gas properties	–	–	–	(73,143)	–	**(73,143)**
Gross profit/(loss)	**(11,200)**	**(534)**	**11,046**	**(83,078)**	**(220)**	**(83,986)**

	Year ended – December 31, 2019					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	176,267	123,943	129,789	55,232	–	485,231
NGLs	–	331	–	–	–	331
Gas	277	77,053	–	–	–	77,330
Net sales of oil and gas	176,544	201,327	129,789	55,232	–	562,892
Change in under/over lift position	–	–	–	3,817	–	3,817
Royalties	(20,207)	(7,597)	–	–	–	(27,804)
Hedging settlement	(1,971)	(374)	–	–	–	(2,345)
Other operating revenue	–	–	15,513	1,005	671	17,189
Revenue	154,366	193,356	145,302	60,054	671	553,749
Production costs (including inventory movements)	(70,165)	(107,333)	(33,378)	(29,895)	–	(240,771)
Depletion	(28,441)	(49,236)	(30,077)	(13,905)	–	(121,659)
Depreciation of other assets	–	–	(23,020)	–	–	(23,020)
Exploration and business development costs	(44)	–	(13,697)	–	(1,654)	(15,395)
Gross profit/(loss)	55,716	36,787	45,130	16,254	(983)	152,904

[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 months and year ended December 31, 2020, Review

Revenue

Total revenue amounted to USD 103,353 thousand for Q4 2020 compared to USD 145,535 thousand for Q4 2019 and USD 324,164 thousand for the year ended December 31, 2020, compared to USD 553,749 thousand for the year ended December 31, 2019, and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	2020	2019	2020	2019
Crude oil sales	89,089	124,526	263,517	485,231
Gas and NGL sales	18,697	19,536	60,164	77,661
Change in under/overlift position	2,430	3,030	(630)	3,817
Royalties	(5,550)	(6,500)	(14,064)	(27,804)
Hedging settlement	(5,733)	523	(1,983)	(2,345)
Other operating revenue	4,420	4,420	17,160	17,189
Total revenue	**103,353**	145,535	**324,164**	553,749

The main components of total revenue for the three months and year ended December 31, 2020, and December 31, 2019, respectively are detailed below.

Crude oil sales

	Three months ended – December 31, 2020				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	31,835	28,352	18,569	10,333	**89,089**
- Quantity sold in bbls	1,113,135	860,551	395,244	225,974	**2,594,904**
- Average price realized USD per bbl	28.60	32.95	46.98	45.73	**34.33**

	Three months ended – December 31, 2019				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	43,791	27,950	36,618	16,167	124,526
- Quantity sold in bbls	1,273,314	683,853	522,197	252,902	2,732,266
- Average price realized USD per bbl	34.39	40.87	70.12	63.92	45.58

Crude oil revenue was 28% lower for Q4 2020 compared to Q4 2019 mainly due to lower oil prices resulting from a drop in global oil demand triggered by the impact of the global Covid-19 outbreak. Crude oil prices started to recover towards the end of Q2 2020 from the low seen in April 2020 and the Group commenced the progressive resumption of Canadian oil production and entered into additional oil price hedges in relation to a proportion of the Canadian oil production for the second half of the year.

The Suffield Assets crude oil in Canada is 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 – Southern Assets. The realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q4 2020, WTI averaged USD 43 per bbl compared to USD 57 per bbl for Q4 2019 and the average discount from WTI to WCS used in our pricing formula was USD 9 per bbl compared to USD 16 per bbl for Q4 2019.

Onion Lake Thermal and other Canadian assets production (shown under Canada – Northern Assets) is heavier than the WCS quality and trades at a discount to WCS prices. Part of the Onion Lake production is being blended from July 2020 to meet pipeline specifications and is sold at a higher price than non-blended crude.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices with revenue in France based on one month forward Brent prices. There were two cargo liftings in Malaysia during Q4 2020 compared to three cargo liftings in Q4 2019. The average Dated Brent crude oil price was USD 44 per bbl for Q4 2020 compared to USD 63 per bbl for the comparative period in 2019.

	Year ended – December 31, 2020				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	89,206	78,146	60,465	35,700	**263,517**
- Quantity sold in bbls	4,000,485	2,821,549	1,358,097	998,700	**9,178,831**
- Average price realized USD per bbl	22.30	27.70	44.52	35.75	**28.71**

	Year ended – December 31, 2019				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	176,267	123,943	129,789	55,232	485,231
- Quantity sold in bbls	4,637,206	2,715,914	1,857,694	870,380	10,081,194
- Average price realized USD per bbl	38.01	45.64	69.87	63.46	48.13

Crude oil sales revenues were 46% lower for the year ended December 31, 2020, compared to the year ended December 31, 2019, mainly due to a 40% reduction in achieved oil prices as a result of the drop in global oil demand triggered by the impact of the Covid-19 outbreak.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. WTI averaged USD 40 per bbl and the average discount from WTI to WCS was approximately USD 13 per bbl for the year ended December 31, 2020, compared to an average WTI of USD 57 per bbl and an average discount from WTI to WCS of USD 13 per bbl for the comparative period in 2019.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 42 per bbl for the year ended December 31, 2020, compared to USD 64 per bbl for the comparative period in 2019.

Gas and NGL sales

	Three months ended – December 31, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	18,600	97	**18,697**
- Quantity sold in Mcf	8,922,304	54,072	**8,976,376**
- Average price realized USD per Mcf	2.08	1.79	**2.08**

	Three months ended – December 31, 2019		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	19,414	122	19,536
- Quantity sold in Mcf	9,358,478	71,640	9,430,118
- Average price realized USD per Mcf	2.07	1.70	2.07

Gas and NGL sales revenue was 4% lower for Q4 2020 compared to Q4 2019. The Suffield gas production is approximately 98% sold on the Alberta/Saskatchewan border at Empress.

	Year ended – December 31, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	59,830	334	**60,164**
- Quantity sold in Mcf	35,113,522	224,252	**35,337,774**
- Average price realized USD per Mcf	1.70	1.49	**1.70**

	Year ended – December 31, 2019		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	77,384	277	77,661
- Quantity sold in Mcf	36,829,902	230,592	37,060,494
- Average price realized USD per Mcf	2.10	1.20	2.10

In Canada, gas and NGL sales revenue was 23% lower during the year ended December 31, 2020, compared to the comparative period in 2019 due to the lower achieved gas price. For the year ended December 31, 2020, IPC realized an average price of CAD 2.28 per Mcf compared to CAD 2.77 per Mcf for the comparative period in 2019. The average pricing at Empress for 2020 was CAD 2.22 per Mcf.

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. It 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. Also see the "Financial Position and Liquidity" and the "Financial Risk Management" sections below.

The realized hedging settlements for Q4 2020 amounted to a loss of USD 5,733 thousand and for the year ended December 31, 2020, amounted to a loss of USD 1,983 thousand, consisting of a gain of USD 671 thousand on the gas contracts and a loss of USD 2,654 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 4,420 thousand for Q4 2020 compared to USD 4,420 thousand for Q4 2019 and USD 17,160 thousand for the year ended December 31, 2020, compared to USD 17,189 thousand for the year ended December 31, 2019. 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 is third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia.

Production costs

Production costs including inventory movements amounted to USD 57,222 thousand for Q4 2020 compared to USD 65,322 thousand for Q4 2019 and USD 204,628 thousand for the year ended December 31, 2020, compared to USD 240,771 thousand for the year ended December 31, 2019, and is analyzed as follows:

	Three months ended – December 31, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	20,367	14,176	18,621	7,597	(11,730)	**49,031**
USD/boe[2]	8.60	12.71	48.62	28.70	n/a	**11.87**
Cost of blending	3,106	3,677	–	–	–	**6,783**
Change in inventory position	62	(693)	1,912	127	–	**1,408**
Production costs	**24,106**	**16,589**	**20,533**	**7,724**	**(11,730)**	**57,222**

	Three months ended – December 31, 2019					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	19,616	19,194	18,189	8,286	(11,730)	53,555
USD/boe[2]	8.71	14.71	36.87	28.24	n/a	12.33
Cost of blending	5,069	–	–	–	–	5,069
Change in inventory position	567	–	5,827	304	–	6,698
Production costs	25,252	19,194	24,016	8,590	(11,730)	65,322

	Year ended – December 31, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	75,054	57,616	72,152	25,639	(46,665)	**183,796**
USD/boe[2]	8.48	14.69	44.47	25.14	n/a	**11.92**
Cost of blending	13,334	7,357	–	–	–	**20,691**
Change in inventory position	371	(350)	(694)	814	–	**141**
Production costs	**88,759**	**64,623**	**71,458**	**26,453**	**(46,665)**	**204,628**

USD Thousands	Year ended – December 31, 2019 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	85,419	70,165	75,471	29,291	(46,538)	213,808
USD/boe[2]	9.62	14.60	35.78	31.89	n/a	12.79
Cost of blending	21,919	–	–	–	–	21,919
Change in inventory position	(5)	–	4,445	604	–	5,044
Production costs	107,333	70,165	79,916	29,895	(46,538)	240,771

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

[2] *USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period.*

[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating cost per boe for Malaysia to USD 17.99 and USD 13.09 for Q4 2020 and Q4 2019, respectively, and USD 15.71 and USD 13.72 for the year ended December 31, 2020, and the year ended December 31, 2019, respectively.*

Operating costs

Operating costs amounted to USD 49,031 thousand for Q4 2020 compared to USD 53,555 thousand for Q4 2019 and USD 183,796 thousand for the year ended December 31, 2020, compared to USD 213,808 thousand for the year ended December 31, 2019. Operating costs per boe amounted to USD 11.87 per boe in Q4 2020 compared with USD 12.33 per boe in Q4 2019 and to USD 11.92 per boe for the full year 2020 which was at the lower end of CMD guidance of USD 12 to 13 per boe. During 2020, in respect of relief subsidies related to the Covid-19 pandemic provided by governmental authorities to oil and gas companies, the Group received approximately USD 5,900 thousand, including wage subsidies and site rehabilitation costs.

Cost of blending

For the Suffield Assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. From 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 6,783 thousand for Q4 2020 compared to USD 5,069 thousand for Q4 2019 and USD 20,691 thousand for the year ended December 31, 2020, compared to USD 21,919 thousand for the year ended December 31, 2019.

As a result of the blending, actual sales volumes are higher than produced barrels. A profit of USD 11 thousand and a cost of USD 445 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q4 2020 and Q4 2019 respectively, and costs of USD 1,258 thousand and USD 2,289 thousand were recognized for the year ended December 31, 2020, and December 31, 2019, 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 year 2020, IPC had crude entitlement of 81,000 barrels of oil on the FPSO Bertam facility.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 29,793 thousand for Q4 2020 compared to USD 32,458 thousand for Q4 2019 and USD 111,896 thousand for the year ended December 31, 2020, compared to USD 121,659 thousand for the year ended December 31, 2019. The depletion charge is analyzed in the following tables:

	Three months ended – December 31, 2020				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	11,262	7,381	6,553	4,597	**29,793**
USD per boe	4.76	6.62	17.11	17.37	**7.21**

	Three months ended – December 31, 2019				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	12,560	8,283	7,034	4,581	32,458
USD per boe	5.58	6.35	14.26	15.61	7.47

	Year ended – December 31, 2020				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	40,555	26,255	27,759	17,327	**111,896**
USD per boe	4.58	6.70	17.11	16.99	**7.26**

	Year ended – December 31, 2019				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	49,236	28,441	30,077	13,905	121,659
USD per boe	5.55	5.92	14.26	15.14	7.28

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

Depreciation of other assets

The total depreciation of other assets amounted to USD 2,751 thousand for Q4 2020 compared to USD 3,805 thousand for Q4 2019 and USD 11,681 thousand for the year ended December 31, 2020, compared to USD 23,020 thousand for the year ended December 31, 2019. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves. Prior to this date the Bertam FPSO was being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Exploration and business development costs

The total exploration and business developments costs amounted to USD 1,014 thousand for Q4 2020 and USD 6,802 thousand for the year ended December 31, 2020. The charge in Q4 2020 mainly relates to study costs in Malaysia. The full year costs also includes exploration costs expensed in France as future development on the exploration licences is unlikely and to appraisal wells drilled in Canada in 2019 where performance was below expectation.

Impairment costs of oil and gas properties

A non-cash impairment charge of USD 73,143 thousand pre-tax (USD 54,254 thousand after tax) was taken as a result of the impairment testing performed at the year end. The impairment related to the Paris Basin assets in France, as a result of lower oil pricing, the estimated impact of additional transportation costs following the announcement of the closure of the Total operated Grandpuits refinery and the reflection of cessation of production in 2040 in accordance with the French hydrocarbon law.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 12,788 thousand for the year ended December 31, 2020, compared to USD 12,042 thousand for the year ended December 31, 2019.

Net financial items

Net financial items amounted to a credit of USD 14,987 thousand for the year ended December 31, 2020, compared to USD 18,026 thousand for the year ended December 31, 2019, and included a largely non-cash net foreign exchange gain of USD 13,028 thousand for 2020 compared to a net foreign exchange gain of USD 9,553 thousand for 2019. The foreign exchange movements mainly result from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 28,015 thousand for the year ended December 31, 2020, compared to USD 27,579 thousand for the year ended December 31, 2019.

The interest expense amounted to USD 13,401 thousand for the year ended December 31, 2020, compared to interest expense USD 17,508 thousand for the comparative period in 2019. The comparative interest expense in 2019 includes interest on senior notes acquired on the BlackPearl acquisition and the make whole provision costs when repaying these in Q2 2019.

The unwinding of the asset retirement obligation discount rate amounted to USD 10,837 thousand for the year ended December 31, 2020, compared to USD 10,664 thousand for year ended December 31, 2019.

Income tax

The corporate income tax amounted to a credit of USD 33,820 thousand for the year ended December 31, 2020, compared to a charge of USD 19,248 thousand for the year ended December 31, 2019. The income tax movements in 2020 relate to deferred taxes with minimal cash taxes and includes a USD 18,889 thousand deferred tax credit on the impairment charge relating to the Paris Basin assets reflected at the year end,

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the year ended December 31, 2020, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	15,637	25,179	20,274	11,323	**72,413**
Exploration and evaluation	–	4,264	460	522	**5,246**
	15,637	29,443	20,735	11,845	**77,659**

Capital expenditure of USD 77,659 thousand was mainly spent on drilling on the Suffield Assets, the development of the Pad D' on Onion Lake Thermal and the continued drilling campaign in Malaysia. USD 56,190 thousand of the capital expenditure was spent in Q1 2020, with discretionary capital spend reduced thereafter in connection with IPC's business reset.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 59,198 thousand as at December 31, 2020, which included USD 55,647 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.

Granite Acquisition

On March 5, 2020, IPC completed the acquisition (the "Granite Acquisition") of all of the issued and outstanding shares of Granite Oil Corp. ("Granite"). At such date, Granite became a wholly-owned subsidiary of IPC.

The Granite Acquisition has been accounted for as a business combination in accordance with IFRS 3, with IPC being the acquirer. Total consideration provided, after preliminary closing adjustments, amounted to USD 27.7 million (CAD 37.1 million).

The amounts recognized in respect of the identifiable assets acquired and liabilities assumed are as set out in the table below.

USD Thousands	
Trade and other receivables	1,620
Prepaid expenses and deposits	599
Fair value of risk management assets	1,748
Deferred tax assets	16,730
Property, plant and equipment	47,076
Other fixed assets	85
Accounts payable and accrued liabilities	(6,691)
Decommissioning liabilities	(4,498)
Long-term debt	(27,649)
MTM reserve in equity	(1,311)
Total Consideration	**27,709**
Settled by:	
Cash payment for 39,061,575 common shares of Granite	**27,709**

The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the Granite Acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed. No such further adjustments are expected.

Acquisition-related costs of approximately USD 0.5 million have been recognized in the statement of operations for the year ended December 31, 2020.

Financial Position and Liquidity

Financing

As at January 1, 2019, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had reserve-based lending credit facilities in aggregate of CAD 320 million and outstanding senior secured notes of CAD 75 million in connection with its oil and gas assets in Canada.

In June 2019, the Group combined its reserve-based lending facilities in Canada into one reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021. The senior secured notes of CAD 75 million were fully repaid and cancelled in June 2019, from a drawdown under the Canadian RBL.

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. The France Facility has an initial term of 12 months and is extendable by the Group for up to a further five years at IPC's discretion. IPC intends to extend the France Facility for the additional five years. The France Facility amount was fully drawn as at December 31, 2020 and as at February 9, 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 July 2020, the Group also amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended by 12 months until the end of May 2022. Under the Canadian RBL, the Group is required, and has satisfied the requirement, to hedge 30% of forecast production in Canada (other than in respect of the Ferguson asset) over the period from October 1, 2020 to June 30, 2021.

In March 2020, in connection with the completion of the Granite Acquisition, the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility"). In December 2020, the Granite Facility was amended to a CAD 30 million revolving credit facility, reducing down to CAD 25 million as at July1, 2021 with a maturity of December 21, 2021. The Granite Facility was drawn as to CAD 29 million as at December 31, 2020. Under the Granite Facility, the Group is required, and has satisfied the current requirement, to hedge 50% of forecast production up to December 31, 2021 in respect of the Ferguson asset.

The borrowing base availability under the International RBL was agreed in December 2020 at USD 102 million of which USD 80 million was drawn as at December 31, 2020. The borrowing base availability under the Canadian RBL was amended in December 2020 to CAD 325 million of which CAD 266 million was drawn as at December 31, 2020.

Total net debt as at December 31, 2020 amounted to USD 321.2 million.

With the exception of the Granite Facility , no facility repayment schedule results in mandatory repayment within the twelve months following December 31, 2020. As such, the amounts drawn under the International RBL, the France Facility and the Canadian RBL as at December 31, 2020 are classified as non-current.

The Group is in compliance with the covenants of the financing facilities as at December 31, 2020.

Cash and cash equivalents held amounted to USD 6,498 thousand as at December 31, 2020. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at December 31, 2020, the Group had a net negative working capital balance including cash of USD 4,670 thousand compared to a positive working capital balance of USD 12,409 thousand as at December 31, 2019. The difference as at December 31, 2020 from December 31, 2019 is mainly as a result of lower trade receivables due to the lower oil price and the reclassification of the Granite Facility outstanding amount to current liabilities from non-current during the year. The outstanding amount under the Granite Facility as at December 31, 2020 was USD 22,982 thousand and is included in the net debt balance of USD 321.2 million as at December 31, 2020.

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 are therefore unlikely to 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 abandonment 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 December 31		Year ended December 31	
USD Thousands	**2020**	2019	**2020**	2019
Revenue	103,353	145,535	324,164	553,749
Production costs	(57,222)	(65,322)	(204,628)	(240,771)
Current tax	(112)	(1,325)	(113)	(5,034)
Operating cash flow	**46,019**	78,888	**119,423**	307,944

Free cash flow

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

USD Thousands	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Operating cash flow - see above	46,019	78,888	119,423	307,944
Capital expenditures	(7,732)	(66,471)	(77,659)	(180,587)
Abandonment and farm-in expenditures[1]	(2,109)	(1,674)	(6,138)	(8,137)
General, administration and depreciation expenses before depreciation[2]	(3,127)	(2,861)	(11,085)	(10,465)
Cash financial items[3]	(4,480)	(3,450)	(15,199)	(19,447)
Free cash flow	**28,571**	4,432	**9,342**	89,308

[1] *See note 20 to the financial statements*

[2] *Depreciation is not specifically disclosed in the Financial Statements*

[3] *See notes 5 and 6 to the financial statements. 2019 full year excludes other financial income of USD 4,576 thousand which is non-cash.*

EBITDA

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

USD Thousands	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Net result	(45,250)	38,372	(77,941)	103,588
Net financial items	(6,731)	(3,429)	14,987	18,026
Income tax	(12,139)	4,984	(33,820)	19,248
Depletion	29,793	32,458	111,896	121,659
Depreciation of other assets	2,751	3,805	11,681	23,020
Impairment	73,143	–	73,143	–
Exploration and business development costs	1,014	705	6,802	15,395
Depreciation included in general, administration and depreciation expenses[1]	423	458	1,703	1,577
EBITDA	**43,004**	77,353	**108,451**	302,513

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

Operating costs

The following table sets out how operating costs is calculated:

USD Thousands	Three months ended December 31 2020	Three months ended December 31 2019	Year ended December 31 2020	Year ended December 31 2019
Production costs	57,222	65,322	204,628	240,771
Cost of blending[1]	(6,783)	(5,069)	(20,691)	(21,919)
Change in inventory position	(1,408)	(6,698)	(141)	(5,044)
Operating costs	**49,031**	53,555	**183,796**	213,808

[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	December 31, 2020	December 31, 2019
Bank loans	327,691	247,074
Cash and cash equivalents	(6,498)	(15,571)
Net debt	**321,193**	231,503

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has issued a letter of credit for an amount of CAD 2.6 million in respect of its obligations to purchase diluent. This letter of credit is outstanding up to October 31, 2021.

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.

In connection with the Granite Acquisition, IPC, through its subsidiary Granite, has issued a letter of credit for an amount of CAD 500,000 in respect of its obligations related to the Ferguson asset. This letter of credit increases by CAD 100,000 annually, to a maximum of CAD 1,000,000.

Outstanding Share Data

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

As at January 1, 2019, the total number of common shares issued and outstanding in IPC was 163,720,065. In November 2019, IPC announced the commencement of a share repurchase program. During the period up to the end of Q1 2020, IPC repurchased an aggregate of 8,377,308 common shares 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 and as at February 9, 2021, IPC had a total of 155,342,757 common shares issued and outstanding.

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 26.20 % of the outstanding common shares as at February 9, 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 1,808,566 stock options and 3,676,901 IPC Performance and Restricted Share Plan awards (566,652 awards granted in July 2018, 91,012 awards granted in March 2019, 1,190,326 awards granted in July 2019, 25,349 awards granted in January 2020, 1,732,446 awards granted in March 2020, 25,335 awards granted in July 2020 and 45,781 awards granted in January 2021) outstanding as at February 9, 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 20 Provisions of the Financial Statements.

The Bertam field (IPC working interest of 75%) has leased the FPSO Bertam from another Group company for an initial period of six years commencing April 2015, with four one-year options to extend such lease beyond the initial period, 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 (previously "Lundin Petroleum") has charged the Group USD 679 thousand in respect of office space rental and USD 1,086 thousand in respect of shared services provided during the year 2020. The Group has also charged Lundin Energy USD 150 thousand in relation to services provided during Q4 2020.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2020, 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 December 31, 2020, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
January 1, 2021 – March 31, 2021	5,000	AECO Swap	CAD 3.06/GJ
April 1, 2021 – June 30, 2021	40,000	AECO Swap	CAD 2.49/GJ
July 1, 2021 – September 30, 2021	20,000	AECO Swap	CAD 2.53/GJ
October 1, 2021 – October 31, 2021	15,000	AECO Swap	CAD 2.52/GJ

The Group had oil price sales hedges outstanding as at December 31, 2020, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2021 – March 31, 2021	2,200	WCS Swap	USD 27.28/bbl
April 1, 2021 – June 30, 2021	2,150	WCS Swap	USD 27.99/bbl
January 1, 2021 – June 30, 2021	300	WTI Collar	USD 35/bbl - 45.83/bbl
February 1, 2021 – March 31, 2021	300	WCS/WTI Differential	USD 14.78/bbl
April 1, 2021 – June 30, 2021	300	WCS/WTI Differential	USD 14.65/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 1,155 thousand at December 31, 2020.

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

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

The Covid-19 virus and the restrictions and disruptions related to it have had a drastic adverse 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. There can be no assurance that these adverse effects will not continue 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.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified below 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.

Non Financial Risks

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

Future oil and gas development may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Corporation's common shares.

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

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

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

The Covid-19 virus and the restrictions and disruptions related to it have had a drastic adverse 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. There can be no assurance that these adverse effects will not continue 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 the Corporation's common shares.

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

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

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

Climate Change: Physical climate change related risks can be event-driven with increased severity of extreme weather events, such as cyclones, hurricanes, or floods, or long-term shifts in climate patterns with sustained higher temperatures or sea level rise. These physical risks may have financial and operational implications for the Corporation, such as direct damage to assets and indirect impacts from supply chain disruption.

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

Regulatory climate change related risks arise from increased environmental regulation. A breach of such regulations may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity. There is a risk that any such programs, laws or regulations, if proposed and enacted, may contain emission reduction targets which will require substantial capital investments to adapt processes in place or lead to financial penalties or charges as a result of the failure to meet such targets.

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

For example, emission and carbon tax regulations in Canada are evolving and as these regulations are established or amended, they may have an impact on organizations involved in heavy oil production. It is difficult to assess the overall impact these regulations will have on the Group at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on the Group's business.

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases, production interruptions and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; issues and failures affecting the FPSO Bertam; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may cause production delays and interruptions which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Corporation's common shares. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

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

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

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

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

SAGD Recovery Process: The Group has implemented a SAGD recovery process at the Onion Lake Thermal project and would use the SAGD process at the Blackrod project. The SAGD recovery process requires a significant amount of natural gas or other fuels to produce steam for use in the recovery process. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the reservoir can impact the timing, cost and levels of production using this technology. There can be no assurance that the Group's operations will produce at the expected levels or on schedule.

In addition, a significant amount of water is used in SAGD operations. Government regulations apply to access to and use of water. Any shortages in water supplies could lead to increased costs and have a material adverse effect on results of operation and financial condition.

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

The French government has enacted legislation to cease granting new petroleum exploration licenses in France and to restrict the production of oil and gas under existing production licenses in France from 2040. The Group continues to work closely with other industry participants and the French authorities with respect to this legislation.

In Alberta, the oil and gas regulatory authorities have implemented regulations regarding the ability to transfer leases, licenses, permits, wells and facilities between parties. These authorities have increased the minimum abandonment liability rating of the buyer before they will accept a transfer of oil and gas assets. These regulations may make it difficult and costly for producers, such as IPC, to transfer or sell assets to other parties.

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

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

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

Reliance on Third-Party Operators: The Group has partners in many of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party operators which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Corporation's common shares.

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities (for example, Total announced in Q3 2020 that Total is ceasing crude oil transportation, storage and refining operations at the Grandpuits refinery in the Paris Basin, France), could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production or increased operating or transportation costs. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects. In addition, the Covid-19 virus, and the restrictions and disruptions related to it, may adversely affect third-party infrastructure which could have adverse effects on the Corporation, its revenues and cash flows and the market price of the Corporation's common shares.

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

In addition, the maximum amount that the Group is permitted to borrow under its credit facilities is subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the senior credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder. The Covid-19 virus and the restrictions and disruptions related to it have had a drastic adverse effect on the world demand for, and prices of, oil and gas. There can be no assurance that these adverse effects will not continue 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 its access to credit facilities and other debt instruments.

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

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

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

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

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

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

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

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

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

Economic and Political Developments in Countries in which the Group Operates: International operations are subject to political, economic and other uncertainties. The Group's assets could also be adversely affected by changes in applicable laws and policies of Canada, Malaysia and France (including relating to the Covid-19 virus), which could have a negative impact on the Group.

In response to the Covid-19 virus, there are public health restrictions and other related disruptions which could have adverse effects on the business and operations of the Corporation, including production delays or interruptions. 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 the Corporation'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.

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

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

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

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

Significant Shareholder: Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust (the "Trust Entities"), own approximately 26 % of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

Financial Risks

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

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

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

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

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

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

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

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

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the common shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses. The Covid-19 virus and the restrictions and disruptions related to it have had a drastic adverse 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. 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 the common shares.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2020, 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 have had a drastic adverse 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. There can be no assurance that these adverse effects will not continue 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 expectation that recent actions will assist in reducing inventory builds and in rebalancing markets, including supply and demand for oil and gas;
- the potential for an improved future economic environment, including 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 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 2021 expenditures from cash flows and current borrowing capacity;
- IPC's flexibility to remain within existing financial headroom;
- 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, including future oil drilling and gas optimization programs;
- development of the Blackrod project in Canada;
- current and future drilling pad production and timing and success of facility upgrades and tie-in work at Onion Lake Thermal;
- the ability to maintain current and forecast production in France;
- the ability of IPC to identify and implement alternative transportation and marketing options for Paris Basin production in connection with the announced closure of the Total-operated Grandpuits refinery, on terms acceptable to the Corporation;
- the ability of IPC to achieve and maintain current and forecast production in Malaysia;
- the withdrawal of PCSB from the Block PM307 and the ability of IPC to increase its WI in such Block to 100%;
- the existence of future M&A opportunities and the ability of IPC to participate in such opportunities;
- 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;
- estimates of 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 abandonment regulations.

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

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's material change report dated February 9, 2021 (MCR), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2019, (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 MCR.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 272 MMboe as at December 31, 2020, by the mid-point of the 2021 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 MCR. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil reserves/resources disclosed in this MD&A include solution gas and other by-products.

"2P reserves" means proved plus probable reserves. "Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as 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.

The reserves and resources information and data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2020, which will be filed on SEDAR (accessible at www.sedar.com) on or before April 1, 2021. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the MCR available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

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

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

Supplemental Information regarding Product Types

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

	Heavy Crude Oil (Mboepd)	Light and Medium Crude Oil (Mboepd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
September 30, 2019	19.4	7.6	110.1 Mcf (18.4 Mboe)	45.4
December 31, 2019	20.5	8.6	108.8 Mcf (18.1 Mboe)	47.2
September 30, 2020	15.8	8.7	103.5 Mcf (17.3 Mboe)	41.8
December 31, 2020	19.2	8.2	104.7 Mcf (17.4 Mboe)	44.9
Year ended				
December 31, 2019	19.5	8.3	107.9 Mcf (18.0 Mboe)	45.8
December 31, 2020	16.5	8.5	103.1 Mcf (17.2 Mboe)	42.1

This document also makes reference to IPC's forecast total average daily production of 41,000 to 43,000 boepd for 2021. IPC estimates that approximately 44% of that production will be comprised of heavy oil, approximately 18% will be comprised of light and medium crude oil and approximately 38% 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
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
MMbtu	Million British thermal units
Mcf	Thousand cubic feet
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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