Q1

International Petroleum Corporation

Management's Discussion and Analysis

Three months ended March 31, 2021

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "free cash flow" (FCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, FCF, EBITDA, operating costs and net debt that may be used by other public companies. Management believes that OCF, FCF, EBITDA, operating costs and net debt are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 17.

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 22.

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 May 5, 2021, and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited condensed consolidated financial statements and accompanying notes for the three months ended March 31, 2021 ("Financial Statements").

Group Overview
The Group is in the business of exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Canada, Malaysia and France with exposure to growth opportunities.

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

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

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

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

	March 31, 2021		March 31, 2020		December 31, 2020	
	Average	Period end	Average	Year end	Average	Year end
1 EUR equals USD	1.2056	1.1725	1.1023	1.0956	1.1413	1.2271
1 USD equals CAD	1.2668	1.2607	1.3434	1.4254	1.3412	1.2740
1 USD equals MYR	4.9002	4.8618	4.1799	4.3200	4.2026	4.0209

Q1 2021 HIGHLIGHTS

Operational Highlights

- Average net production of approximately 43,700 barrels of oil equivalent (boe) per day (boepd) for the first quarter of 2021 (44% heavy crude oil, 19% light and medium crude oil and 37% natural gas)[1].
- Average net production is above the high end of the 2021 Capital Markets Day (CMD) guidance range for the first quarter of 2021, with exceptional operational performance and high uptimes recorded across IPC's portfolio.
- Full year 2021 average net production is expected to be towards the high end of the forecast 41,000 to 43,000 boepd range[1].
- Operating costs[2] per boe of USD 14.4 for the first quarter of 2021, in line with CMD guidance.
- Capital and decommissioning expenditures of MUSD 12.0 for the first quarter of 2021, in line with CMD guidance.
- Exceptionally strong free cash flow (FCF)[2] generation of MUSD 49 for the first quarter of 2021, representing close to 10% of IPC's market capitalization as at March 31, 2021.
- Increased working interest in the Bertam field, Malaysia to 100% from April 10, 2021.
- Production sustaining Pad D' at Onion Lake Thermal, Canada is on budget and scheduled to come on-line during the second quarter of 2021.
- 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].
- Forecast cumulative FCF[2] for 2021 to 2025 of approximately MUSD 600 to MUSD 900 generating estimated average annual free cash flow yield over the five year period of between 24% and 36%[3].

Financial Highlights

	Three months ended March 31	
USD Thousands	2021	2020
Revenue	**134,284**	80,536
Gross profit / (loss)	**37,930**	(12,436)
Net result	**26,891**	(40,069)
Operating cash flow[2]	**67,721**	21,481
Free cash flow[2]	**48,951**	(42,712)
EBITDA[2]	**66,263**	19,009
Net Debt[2]	**286,132**	302,473

- Operating cash flow (OCF)[2] generation for the first quarter of 2021 amounted to MUSD 68, above the higher end of the CMD guidance .
- FCF[2] generation for the first quarter of 2021 amounted to MUSD 49.
- Net debt[2] of MUSD 286 as at March 31, 2021.
- Net result of MUSD 27 for the first quarter of 2021.

[1] See "Supplemental Information regarding Product Types" in the "Reserves and Resources Advisory" below and the Corporation's annual information form for the year ended December 31, 2020 (AIF), available on the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).
[2] See definition on page 17 under "Non-IFRS measures".
[3] Assumptions described in IPC's press release of February 9, 2021 available on the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com). Free cash flow yield based on IPC market capitalization at March 31, 2021 (28.3 SEK/share, 8.7 SEK/USD, 505 MUSD). See "Cautionary Statement Regarding Forward-Looking Information" on page 22.

OPERATIONS REVIEW

Business Overview

Market conditions for oil and gas producers have continued to improve during the first months of 2021. First quarter 2021 average Brent oil prices were above USD 60 per barrel, well in excess of fourth quarter 2020 prices that averaged around USD 45 per barrel.

Proactive supply management by the OPEC+ group, led by Saudi Arabia, is allowing the market rebalancing process to continue. The International Energy Agency ("IEA") is now forecasting a net supply deficit in every quarter through 2021 which should set the scene for inventories to return back to longer term norms.

The pace of recovery in oil demand will be dependent on the continued roll out of the Covid-19 vaccination program to the wider population 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+ enters a crucial phase, particularly when considering the timing of easing of the supply curtailments as demand recovers.

In Canada, first quarter 2021 Western Canadian Select ("WCS") crude price differentials averaged below USD 13 per barrel and forward markets into 2022 and 2023 are pricing at around similar levels. Clearly the positive construction progress on both Enbridge's Line 3 replacement as well as the TransMountain pipeline expansion project is providing a much more constructive outlook for Canadian oil market egress relative to the tightness we have witnessed over the past five years or so. IPC has positioned itself well to benefit from this.

Notwithstanding these positive tailwinds, we believe it is prudent to remain cautious with respect to our expenditure plans and therefore we are retaining our limited 2021 expenditure program. We are therefore well placed to deliver on our promise to generate strong free cash flow and to deleverage as we move through 2021.

That being said, the massive collapse in investment in our sector combined with the redirection of future capital investment away from upstream oil and gas in favour of renewable energy by the majors presents a huge opportunity for companies like IPC. We retain our opportunistic approach with respect to further Mergers and Acquisitions ("M&A") activity and we have witnessed an uptick in market activity levels that we anticipate will continue in the months ahead.

First Quarter 2021 Highlights
During the first quarter of 2021, our assets delivered average net production of 43,700 boepd. This sits above the top end of our CMD guidance range for the first quarter and was largely driven by a combination of very high uptime performance across all assets as well as a lower than forecast cold weather impact on our Canadian gas production. As a result of strong start to 2021, we expect full year 2021 net average production to be towards the high end of our forecast 41,000 to 43,000 boepd range. Our operating costs per boe for the first quarter of 2021 was USD 14.4, in line with CMD guidance.

Operating cash flow generation for the first quarter of 2021 amounted to MUSD 68, stronger than our CMD high case (Brent USD 65 per barrel) forecast as a result of stronger than forecast production, tighter Canadian crude price differentials and stronger realized Canadian gas prices.

Capital and decommissioning expenditures during the first quarter of 2021 of MUSD 12.0 was in line with forecast, representing approximately one third of our full year forecast expenditure program of MUSD 37.

During the first quarter of 2021, free cash flow generation was exceptionally strong at MUSD 49 which represents close to 10% of IPC's market capitalization as at March 31, 2021.

Net debt was reduced during the first quarter of 2021 by MUSD 35 to MUSD 286. Net debt to EBITDA drops to 1.8 times as at March 31, 2021 from 3 times as at December 31, 2020 (based on the trailing 12 months' EBITDA) or to 1.1 times as at March 31, 2021 (based on an annualized Q1 2021 EBITDA).

Acquisition of additional Bertam interest in Malaysia
During April 2021, we were very pleased to acquire an additional 25% interest in the Bertam field on the withdrawal of our partner Petronas Carigali, taking IPC's interest in the field to 100% effective from April 10, 2021. No consideration was paid by IPC for this additional interest and IPC agreed to assume minimal further future well decommissioning obligations estimated at around MUSD 1.0. Current net Bertam field production acquired is in excess of 1,250 bopd. Our commercial interest in the Bertam FPSO remains unchanged at 100%.

Environmental, Social and Governance ("ESG") Performance
Health, Safety & Environmental performance remains a priority for all operational assets. Our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During the first quarter of 2021, IPC recorded no material safety or environmental incidents.

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

Operations Overview

Reserves and Resources

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

IPC has forecast a limited capital budget for 2021, with the short term focus on free cash flow delivery to the business. IPC remains focused on organic growth and continues to mature future development projects, with a significant portfolio of drilling and optimization opportunities ready for sanction at the discretion of the Group. IPC continues to review all operational and development activities to identify and prioritize those with highest returns whilst preserving strong free cash flow generation.

Production

The average net production during the first quarter of 2021 exceeded the high end of CMD guidance at 43,700 boepd. The exceptional production delivery was driven in Canada by strong reservoir performance and high production uptime across all assets. In addition, there was exceptional operational performance and facility uptime at the Bertam field in Malaysia and stable production performance in France with optimization activity offsetting natural production declines.

The production during Q1 2021 with comparatives are summarized below:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2021	2020	2020
Crude oil			
Canada – Northern Assets	11.8	13.4	10.6
Canada – Southern Assets	8.8	7.8	7.1
Malaysia	4.0	4.6	4.4
France	2.9	3.2	2.8
Total crude oil production	**27.5**	29.0	24.9
Gas			
Canada – Northern Assets	0.1	0.1	0.1
Canada – Southern Assets	16.1	16.9	17.1
Total gas production	**16.2**	17.0	17.2
Total production	**43.7**	46.0	42.1
Quantity in MMboe	**3.93**	4.19	15.42

CANADA

Production in Mboepd	WI	Three months ended March 31 2021	Three months ended March 31 2020	Year ended December 31 2020
- Oil Onion Lake Thermal	100%	10.1	11.2	9.5
- Oil Suffield	100%	7.6	6.5	5.9
- Oil Ferguson	100%	1.2	1.3	1.2
- Oil Other	50-100%	1.7	2.2	1.1
- Gas	99.7%[1]	16.2	17.0	17.2
Canada		**36.8**	38.2	34.9

[1] *On a well count basis*

Production
Net production from the Canadian assets during Q1 2021 was ahead of CMD guidance at 36,800 boepd. The strong production delivery was primarily driven by exceptional operational performance at the Suffield assets, underpinned by ahead of expectation production recovery from the N2N Enhanced Oil Recovery ASP (Alkaline Surfactant Polymer) project.

Organic Growth and Capital Projects
In Canada, IPC has forecast a limited capital budget for 2021. IPC continues to mature future development projects, with a significant portfolio of drilling and optimization opportunities ready for sanction at the discretion of the Group.

At Onion Lake Thermal, the production sustaining Pad D' is on budget and scheduled to come on-line during the second quarter of 2021. As of the end of Q1 2021, all facility modules are set on location. Final construction activity, facility commissioning and well steam injection start-up is forecast through Q2 2021.

During Q1 2021, production ramp up and testing of the third well pair at the Blackrod SAGD pilot project continued. Heat conformance and production performance remain ahead of expectations.

MALAYSIA

Production in Mboepd	WI	Three months ended March 31 2021	Three months ended March 31 2020	Year ended December 31 2020
Bertam	75%	4.0	4.6	4.4

Production
Net production from the Bertam field on Block PM307 during Q1 2021 was ahead of CMD guidance at 4,000 boepd with excellent operational performance and facility uptime close to 100% at FPSO Bertam.

Petronas Carigali Sdn Bhd, previously the holder of a 25% WI in Block PM307, completed its withdrawal from the Block effective as of April 2021. From April 2021, IPC has increased its working interest at the Bertam field from 75% to 100%.

Organic Growth and Capital Projects
In Malaysia, IPC has forecast a limited capital budget for 2021. IPC continues to mature future development projects, with the potential drilling of the A-15 well and well rate optimization opportunities ready for sanction at the discretion of the Group.

FRANCE

Production in Mboepd	WI	Three months ended March 31 2021	Three months ended March 31 2020	Year ended December 31 2020
- Paris Basin	100%[1]	2.5	2.8	2.4
- Aquitaine	50%	0.4	0.4	0.4
France		2.9	3.2	2.8

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

Production
Net production in France during Q1 2021 was ahead of CMD guidance at 2,900 boepd with steady production and good uptime at the major producing fields. In Q1 2021, strong reservoir performance continued at the Vert-la-Gravelle development supported by increased water injection.

Following the decision by Total to discontinue crude oil refining at its Grandpuits refinery, IPC has agreed a sales contract with Total for delivery of IPC's Paris Basin oil production to alternative refineries until end 2026. IPC expects that this marketing arrangement will increase IPC's net operating costs in France by around USD 5 per bbl commencing in 2021, as compared to average 2020 levels.

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

FINANCIAL REVIEW

Financial Results

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q1-21	Q4-20	Q3-20	Q2-20	Q1-20	Q4-19	Q3-19	Q2-19
Revenue	**134,284**	103,353	95,346	44,929	80,536	145,535	131,437	129,357
Gross profit	**37,930**	(60,570)	5,557	(16,537)	(12,436)	43,245	23,487	39,287
Net result	**26,891**	(45,250)	8,850	(1,472)	(40,069)	38,372	6,330	25,744
Earnings per share – USD	**0.17**	(0.29)	0.06	(0.01)	(0.25)	0.23	0.04	0.16
Earnings per share fully diluted – USD	**0.17**	(0.29)	0.06	(0.01)	(0.25)	0.23	0.04	0.15
Operating cash flow[1]	**67,721**	46,019	37,181	14,742	21,481	78,888	69,504	76,496
EBITDA[1]	**66,263**	43,004	34,251	12,187	19,009	77,353	68,885	74,600
Net debt at period end[1]	**286,132**	321,193	322,092	341,367	302,473	231,503	207,778	239,322

[1] *See definition on page 17 under "Non-IFRS measures"*

Summarized interim consolidated balance sheet information is as follows:

USD Thousands	March 31, 2021	December 31, 2020
Non-current assets	1,220,196	1,240,653
Current assets	121,128	92,467
Total assets	**1,341,324**	1,333,120
Total non-current liabilities	498,657	527,530
Current liabilities	108,677	97,137
Total liabilities	**607,334**	624,667
Net assets	**733,990**	708,453
Working capital (including cash)	**12,451**	(4,670)

Segment Information

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

	Three months ended – March 31, 2021					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	50,554	38,679	13,033	23,171	–	**125,437**
NGLs	–	116	–	–	–	**116**
Gas	131	19,589	–	–	–	**19,720**
Net sales of oil and gas	**50,685**	**58,384**	**13,033**	**23,171**	**–**	**145,273**
Change in under/over lift position	–	–	–	(4,130)	–	**(4,130)**
Royalties	(4,122)	(3,159)	–	–	–	**(7,281)**
Hedging settlement	(2,234)	(1,666)	–	–	–	**(3,900)**
Other operating revenue	–	–	3,825	281	216	**4,322**
Revenue	**44,329**	**53,559**	**16,858**	**19,322**	**216**	**134,284**
Production costs (including inventory movements)	(29,355)	(28,972)	2,576	(9,871)	–	**(65,622)**
Depletion	(6,840)	(10,406)	(6,769)	(4,055)	–	**(28,070)**
Depreciation of other assets	–	–	(2,269)	–	–	**(2,269)**
Exploration and business development costs	–	–	–	(7)	(386)	**(393)**
Gross profit/(loss)	**8,134**	**14,181**	**10,396**	**5,389**	**(170)**	**37,930**

	Three months ended – March 31, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	22,125	17,882	16,855	8,733	–	65,595
NGLs	–	77	–	–	–	77
Gas	72	14,714	–	–	–	14,786
Net sales of oil and gas	22,197	32,673	16,855	8,733	–	80,458
Change in under/over lift position	–	–	–	(3,357)	–	(3,357)
Royalties	(2,288)	(1,436)	–	–	–	(3,724)
Hedging settlement	2,330	523	–	–	–	2,853
Other operating revenue	–	–	3,868	276	162	4,306
Revenue	22,239	31,760	20,723	5,652	162	80,536
Production costs (including inventory movements)	(18,630)	(27,017)	(6,261)	(7,233)	–	(59,141)
Depletion	(8,230)	(9,824)	(7,207)	(5,013)	–	(30,274)
Depreciation of other assets	–	–	(3,035)	–	–	(3,035)
Exploration and business development costs	–	–	–	–	(522)	(522)
Gross profit/(loss)	(4,621)	(5,081)	4,220	(6,594)	(360)	(12,436)

[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 ended March 31, 2021, Review

Revenue
Total revenue amounted to USD 134,284 thousand for Q1 2021, compared to USD 80,536 thousand for Q1 2020 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	2021	2020
Crude oil sales	125,437	65,595
Gas and NGL sales	19,836	14,863
Change in under/overlift position	(4,130)	(3,357)
Royalties	(7,281)	(3,724)
Hedging settlement	(3,900)	2,853
Other operating revenue	4,322	4,306
Total revenue	134,284	80,536

The main components of total revenue for Q1 2021 and Q1 2020 are detailed below.

Crude oil sales

	Three months ended – March 31, 2021				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	50,554	38,679	13,033	23,171	125,437
- Quantity sold in bbls	1,188,133	867,169	201,132	358,842	2,615,276
- Average price realized USD per bbl	42.55	44.60	64.80	64.57	47.96

	Three months ended – March 31, 2020				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	22,125	17,882	16,855	8,733	65,595
- Quantity sold in bbls	1,209,907	677,495	344,561	260,005	2,491,968
- Average price realized USD per bbl	18.29	26.39	48.92	33.59	26.32

Crude oil revenue was 91% higher for Q1 2021 compared to Q1 2020 mainly due to higher oil prices resulting from the improvement of market conditions for oil and gas producers.

The Suffield area assets and part of the Onion Lake crude oil in Canada are blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q1 2021, WTI averaged USD 58 per bbl compared to USD 46 per bbl for Q1 2020 and the average discount to WCS used in our pricing formula was USD 12 per bbl compared to USD 21 per bbl for Q1 2020.

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 was one cargo lifting in Malaysia during Q1 2021 in February compared to two cargo liftings in Q1 2020. Produced unsold oil barrels from Bertam are 185,000 barrels, see Change in Inventory Position section below. There was also an Aquitaine cargo of 131 Mbbl lifted in Q1 2021 with an achieved price of USD 65.89/bbl. The average Dated Brent crude oil price was USD 61 per bbl for Q1 2021 compared to USD 50 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – March 31, 2021		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	19,705	131	**19,836**
- Quantity sold in Mcf	8,000,169	55,079	**8,055,248**
- Average price realized USD per Mcf	2.46	2.37	**2.46**

	Three months ended – March 31, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	14,791	72	14,863
- Quantity sold in Mcf	8,657,473	58,684	8,716,157
- Average price realized USD per Mcf	1.71	1.23	1.71

Gas and NGL sales revenue was 33% higher for Q1 2021 compared to Q1 2020. Approximately 98% of the Suffield gas production was sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered in Alberta based on AECO pricing. For Q1 2021, IPC realized an average price of CAD 3.11 per Mcf which was in line with Empress average pricing for Q1 2021 of CAD 3.20 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 settlement for Q1 2021 amounted to a loss of USD 3,900 thousand and consisted of a gain of USD 35 thousand on the gas contracts and a loss of USD 3,935 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 4,322 thousand for Q1 2021 compared to USD 4,306 thousand for Q1 2020 and 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 65,622 thousand for Q1 2021 compared to USD 59,141 thousand for Q1 2020 and is analyzed as follows:

	Three months ended – March 31, 2021					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	23,619	17,208	17,136	10,153	(11,475)	**56,641**
USD/boe[2]	10.56	16.10	47.70	37.90	n/a	**14.40**
Cost of blending	5,928	12,516	–	–	–	**18,444**
Change in inventory position	(575)	(369)	(8,237)	(282)	–	**(9,463)**
Production costs	**28,972**	**29,355**	**8,899**	**9,871**	**(11,475)**	**65,622**

USD Thousands	Three months ended – March 31, 2020 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	22,280	18,630	16,808	6,443	(11,603)	52,558
USD/boe[2]	9.90	15.15	39.90	21.97	n/a	12.53
Cost of blending	4,118	–	–	–	–	4,118
Change in inventory position	619	–	1,056	790	–	2,465
Production costs	27,017	18,630	17,864	7,233	(11,603)	59,141

[1] See definition on page 17 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 15.76 and USD 12.36 for Q1 2021 and Q1 2020 respectively.

Operating costs
Operating costs amounted to USD 56,641 thousand for Q1 2021 compared to USD 52,558 thousand for Q1 2020. Operating costs per boe amounted to USD 14.40 per boe in Q1 2021 in line with guidance, compared with USD 12.53 per boe in Q1 2020. During Q1 2021, in repect of relief subsidies related to the Covid-19 pandemic provided by governmental authorities to oil and gas companies, the Group received approximately USD 250 thousand, including wage subsidies and property tax relief.

Cost of blending
For the Suffield area assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Since July 2020, a portion of Onion Lake oil production is also blended and exported by pipeline. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 18,444 thousand for Q1 2021 compared to USD 4,118 thousand for Q1 2020, the increase is attributable to Onion Lake blending and higher diluent prices.

As a result of the blending, actual sales volumes are higher than produced barrels. A gain of USD 70 thousand and a cost of USD 230 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q1 2021 and Q1 2020 respectively.

Change in inventory position
The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion, and market value, and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q1 2021, IPC had crude entitlement of 185,000 barrels of oil on the FPSO Bertam facility (crude produced but unsold).

Depletion and decommissioning costs
The total depletion and decommissioning costs amounted to USD 28,070 thousand for Q1 2021 compared to USD 30,274 thousand for Q1 2020. The depletion charge is analyzed in the following tables:

USD Thousands	Three months ended – March 31, 2021 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,406	6,840	6,769	4,055	**28,070**
USD per boe	4.65	6.40	18.84	15.14	**7.14**

USD Thousands	Three months ended – March 31, 2020 Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	9,824	8,230	7,207	5,013	30,274
USD per boe	4.37	6.69	17.11	17.10	7.22

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

Depreciation of other assets
The total depreciation of other assets amounted to USD 2,269 thousand for Q1 2021 compared to USD 3,035 thousand for Q1 2020. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis over the 2P reserves of the Bertam field.

Exploration and business development costs
The total exploration and business developments costs amounted to USD 393 thousand for Q1 2021. These costs mainly related to business development costs.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 2,818 thousand for Q1 2021, compared to USD 2,810 thousand for Q1 2020.

Net financial items
Net financial items amounted to a charge of USD 8,492 thousand for Q1 2021, compared to a charge of USD 29,162 thousand for Q1 2020, and included a non-cash net foreign exchange loss of USD 678 thousand for Q1 2021 compared to a net foreign exchange loss of USD 21,857 thousand for Q1 2020. During Q2 2020, IPC settled a large part of an intercompany loan which had a significant foreign exchange impact in Q1 2020.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 7,814 thousand for Q1 2021, compared to USD 7,305 thousand for Q1 2020.

The interest expense amounted to USD 3,999 thousand for Q1 2021, compared to USD 3,787 thousand for the comparative period in 2020. The unwinding of the asset retirement obligation discount rate amounted to USD 2,857 thousand for Q1 2021, compared to USD 2,643 thousand for Q1 2020.

Income tax
The corporate income tax amounted to a credit of USD 271 thousand for Q1 2021, compared to a credit of USD 4,339 thousand for Q1 2020.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in Q1 2021, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	3,361	7,492	371	908	**12,132**
Exploration and evaluation	–	(547)	79	7	**(461)**
	3,361	6,945	450	915	**11,671**

Capital expenditure of USD 11,671 thousand was mainly spent on facilities in Canada including Pad D' on Onion Lake Thermal.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 55,579 thousand as at March 31,2021, which included USD 52,288 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves.

Financial Position and Liquidity

Financing

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

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France (the "France Facility") under a financial assistance program instituted by the French government. In April 2021, IPC extended the France Facility until May 2026, with quarterly repayments commencing in August 2022. The France Facility amount was fully drawn as at March 31, 2021 and as at May 5, 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 July 1, 2021 with a maturity of December 31, 2021. The Granite Facility was drawn as to CAD 28 million as at March 31, 2021. 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 63 million was drawn as at March 31, 2021. The borrowing base availability under the Canadian RBL was amended in December 2020 to CAD 325 million of which CAD 255 million was drawn as at March 31, 2021.

Total net debt as at March 31, 2021, amounted to USD 286 million.

With the exception of the Granite Facility, no facility repayment schedule results in mandatory repayment within the next twelve months. As such, the amounts drawn under the International RBL, the France Facility and the Canadian RBL as at March 31, 2021, are classified as non-current.

The Group is in compliance with the covenants under the financing facilities as at March 31, 2021.

Cash and cash equivalents held amounted to USD 17,196 thousand as at March 31, 2021. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at March 31, 2021, the Group had a net working capital balance including cash of USD 12,451 thousand compared to USD (4,670) thousand as at December 31, 2020. The difference as at March 31, 2021, from December 31, 2020, is mainly as a result of higher trade receivables due to the higher oil price and the higher hydrocarbon stocks in Malaysia as only one cargo was lifted during Q1 2021. The outstanding amount under the Granite Facility as at March 31, 2021 was USD 22,460 thousand and is included in the net debt balance of USD 286.1 million as at March 31, 2021.

Non-IFRS Measures

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

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

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

"Free cash flow" is calculated as operating cash flow less capital expenditures less 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 March 31	
USD Thousands	2021	2020
Revenue	134,284	80,536
Production costs	(65,622)	(59,141)
Current tax	(941)	86
Operating cash flow	**67,721**	21,481

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 March 31 2021	2020
Operating cash flow - see above	67,721	21,481
Capital expenditures	(11,671)	(56,190)
Abandonment and farm-in expenditures[1]	(333)	(1,340)
General, administration and depreciation expenses before depreciation[2]	(2,399)	(2,386)
Cash financial items[3]	(4,367)	(4,277)
Free cash flow	**48,951**	(42,712)

[1] See note 16 to the Financial Statements
[2] Depreciation is not specifically disclosed in the Financial Statements
[3] See notes 4 and 5 to the Financial Statements.

EBITDA

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

USD Thousands	Three months ended March 31 2021	2020
Net result	26,891	(40,069)
Net financial items	8,492	29,162
Income tax	(271)	(4,339)
Depletion	28,070	30,274
Depreciation of other assets	2,269	3,035
Exploration and business development costs	393	522
Depreciation included in general, administration and depreciation expenses[1]	419	424
EBITDA	**66,263**	19,009

[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 March 31 2021	2020
Production costs	65,622	59,141
Cost of blending[1]	(18,444)	(4,118)
Change in inventory position	9,463	(2,465)
Operating costs	**56,641**	52,558

[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	March 31, 2021	December 31, 2020
Bank loans	303,328	327,691
Cash and cash equivalents	(17,196)	(6,498)
Net debt	**286,132**	321,193

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 until October 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 acquisition of Granite Oil Corp. ("Granite") in March 2020, 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, 2020, the total number of common shares issued and outstanding in IPC was 159,790,869. In November 2019, IPC announced the commencement of a share repurchase program. In 2020, IPC repurchased 4,448,112 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, IPC had a total of 155,342,757 common shares issued and outstanding.

Following the exercise of stock options during February 2021, the number of issued and outstanding common shares of the Corporation has increased by 25,000 to 155,367,757 common shares As at March 31, 2021, and as at May 5, 2021, IPC had a total of 155,367,757 common shares issued and outstanding with voting rights.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 26.20 % of the outstanding common shares as at May 5, 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 4,552,473 IPC Share Unit Plan awards (566,652 awards granted in July 2018, 88,923 awards granted in March 2019, 1,189,266 awards granted in July 2019, 25,349 awards granted in January 2020, 1,516,038 awards granted in March 2020, 25,335 awards granted in July 2020, 45,781 awards granted in January 2021 and 1,095,129 awards granted in March 2021) outstanding as at May 5, 2021.

Contractual Obligations and Commitments

IPC has an obligation to make payments towards historic costs on Block PM307 in Malaysia payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet – see Note 16 Provisions of the Financial Statements.

The Bertam field 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. Petronas Carigali SDN Bhd withdrew from the Production Sharing Contract and the Joint Operating Agreement for the Bertam Field in Malaysia with an effective date of April 10, 2021 and IPC increased its working interest in the Bertam Field from 75% to 100% as of such date. As of the same date, the Group exercised a one year option to extend the lease of the FPSO Bertam up to April 2022.

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

Lundin Energy has charged the Group USD 162 thousand in respect of office space rental and USD 391 thousand in respect of shared services provided during Q1 2021.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at March 31, 2021, the Corporation had entered into oil and gas price hedges – see below.

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

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

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

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

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

The Group had gas price sale financial hedges outstanding as at March 31, 2021, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
April 1, 2021 – June 30, 2021	40,000	AECO Swap	CAD 2.49/GJ
July 1, 2021 – September 30, 2021	40,000	AECO Swap	CAD 2.51/GJ
October 1, 2021 – October 31, 2021	15,000	AECO Swap	CAD 2.52/GJ

The Group had oil price sale financial hedges outstanding as at March 31, 2021, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
April 1, 2021 – June 30, 2021	500	WTI Swap	USD 59.10/bbl
April 1, 2021 - June 30, 2021	8,300	WCS Swap	USD 42.81/bbl
July 1, 2021 - September 30, 2021	5,350	WCS Swap	USD 45.46/bbl
October 1, 2021 - December 31, 2021	5,000	WCS Swap	USD 44.16/bbl
April 1, 2021 – June 30, 2021	300	WTI Collar	USD 35/bbl - 45.83/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 5,699 thousand at March 31, 2021.

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

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

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

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

RISK AND UNCERTAINTIES

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2020 (AIF) available on SEDAR at www.sedar.com or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

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

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.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

There have been no material changes to the Groups internal control over financial reporting during the three month period ended March 31, 2021, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains statements and information which constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Actual results may differ materially from those expressed or implied by forward-looking statements. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this MD&A, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

The Covid-19 virus and the restrictions and disruptions related to it 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 economic environment resulting from a lack of capital investment and drilling in the oil and gas industry;
- 2021 production range, operating costs and capital and decommissioning expenditure estimates;
- Estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's financial and operational flexibility to continue to react to recent events and navigate the Corporation through periods of low or volatile commodity prices;
- IPC's ability, as market conditions evolve and if determined necessary from time to time, to reduce expenditures and curtail production, and then to resume such production;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- The ability to fully fund 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 implement alternative transportation arrangements for Paris Basin production in connection with the closure of the Total-operated Grandpuits refinery, including at costs estimated by the Corporation;
- The ability to maintain current and forecast production in Malaysia;
- IPC's ability to implement its GHG emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt; and
- Future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:

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

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

Estimated free cash flow generation is based on IPC's current business plans over the period of 2021 to 2025. Assumptions include average net production of approximately 45 Mboepd, average Brent oil prices of USD 55 to 65 per boe escalating by 2% per year, average gas prices of CAD 2.50 per thousand cubic feet, and average Brent to Western Canadian Select differentials as estimated by IPC's independent reserves evaluator and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2020, (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves / resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves / resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (including oil and gas assets acquired in the Granite Acquisition) are effective as of December 31, 2020, and are included in the reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule's December 31, 2020 price forecasts.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2020, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using Sproule's December 31, 2020 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the AIF.

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

The product types comprising the 2P reserves and the contingent resources described in this MD&A are contained in the AIF. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil reserves/resources disclosed in this MD&A include solution gas and other by-products.

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

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

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

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

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

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

The contingent resources reported in the MD&A are estimates only. The estimates are based upon a number of factors and assumptions each of which contains estimation error which could result in future revisions of the estimates as more technical and commercial information becomes available. The estimation factors include, but are not limited to, the mapped extent of the oil and gas accumulations, geologic characteristics of the reservoirs, and dynamic reservoir performance. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Corporation's control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in the MD&A.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

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

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

Supplemental Information regarding Product Types

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

	Heavy Crude Oil (Mboepd)	Light and Medium Crude Oil (Mboepd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
March 31, 2021	19.4	8.1	97.2 Mcf (16.2 Mboe)	43.7
March 31, 2020	19.9	9.2	102.0 Mcf (17.0 Mboe)	46.1
Year ended				
December 31, 2020	16.5	8.5	103.1 Mcf (17.2 Mboe)	42.1

This document also makes reference to IPC's forecast average net daily production of 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.*

DIRECTORS

C. Ashley Heppenstall
Director, Chairman
London, England

Mike Nicholson
Director, President and Chief Executive Officer
Geneva, Switzerland

Chris Bruijnzeels
Director
Abcoude, The Netherlands

Donald K. Charter
Director
Toronto, Ontario, Canada

Torstein Sanness
Director
Oslo, Norway

Emily Moore
Director
Toronto, Ontario, Canada

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

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

William Lundin
Chief Operating Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

Chris Hogue
Senior Vice President Canada
Calgary, Alberta, Canada

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

INVESTOR RELATIONS

Rebecca Gordon
VP Corporate Planning and Investor Relations
Geneva, Switzerland

Sophia Shane
Vancouver, British Columbia, Canada

CORPORATE OFFICE

Suite 2000 – 885 West Georgia Street Vancouver,
British Columbia V6C 3E8 Canada
Telephone: +1 604 689 7842
Facsimile: +1 604 689 4250
Website: www.international-petroleum.com

OPERATIONS OFFICE

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

REGISTERED AND RECORDS OFFICE

Suite 2600 - 595 Burrard Street
Vancouver, British Columbia
V7X 1L3 Canada

INDEPENDENT AUDITORS

PricewaterhouseCoopers SA, Switzerland

TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta, and Toronto, Ontario

MEDIA RELATIONS

Robert Eriksson
Stockholm, Sweden

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and NASDAQ Stockholm
Trading Symbol: IPCO

Corporate Office
International Petroleum Corp
Suite 2000
885 West Georgia Street
Vancouver, BC
V6C 3E8, Canada

Tel: +1 604 689 7842
E-mail: info@international-petroleum.com
Web: international-petroleum.com