Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2019

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to “operating cash flow” (OCF), “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, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, 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 22.

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 27.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Suffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), 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 McDaniel's January 1, 2019, price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Onion Lake, Blackrod and Mooney areas of Canada are effective as of December 31, 2018, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2019, price forecasts.

Reserve estimates, contingent resource estimates, prospective 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, 2018, 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 McDaniel’s January 1, 2019, price forecasts.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated November 5, 2019, and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2019 ("Financial Statements").

Formation of and changes in the Group

In April 2017, Lundin Petroleum AB ("Lundin Petroleum") spun-off its oil and gas assets in Malaysia, France and the Netherlands into a newly formed company called International Petroleum Corporation and distributed the IPC shares, on a pro-rata basis, to Lundin Petroleum shareholders (the "Spin-Off").

On April 24, 2017, the Spin-Off was completed and IPC's shares commenced trading on the Toronto Stock Exchange and Nasdaq First North under the ticker symbol "IPCO". In June 2018, the shares of IPC ceased trading on Nasdaq First North and commenced trading on the Nasdaq Stockholm.

On January 5, 2018, IPC completed the acquisition of the Suffield area oil and gas assets in southern Alberta, Canada (the "Suffield Assets").

On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.

On December 14, 2018, IPC completed the acquisition of all of the issued and outstanding shares of BlackPearl Resources Inc. ("BlackPearl") by way of a plan of arrangement under the Canada Business Corporation Act (the "BlackPearl Acquisition").

The main business of IPC is 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.

Basis of Preparation

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

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

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

	September 30, 2019		September 30, 2018		December 31, 2018	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1237	1.0889	1.1949	1.1576	1.1815	1.1450
1 USD equals CAD	1.3293	1.3248	1.2875	1.3013	1.2958	1.3629
1 USD equals MYR	4.1349	4.1870	3.9904	4.1370	4.0354	4.1325

THIRD QUARTER 2019 HIGHLIGHTS

Share Repurchase Program

- IPC intends to launch a new share repurchase program, the second since our April 2017 spin-off, with the intention to repurchase up to approximately seven percent or 11.5 million IPC shares, the maximum permitted over a twelve month period under Canadian and Swedish securities law. Implementation of the share repurchase program remains subject to Toronto Stock Exchange (TSX) approval.

Operational Highlights

- Average net production of 45,500 barrels of oil equivalent (boe) per day (boepd) for Q3 2019 in line with guidance.
- First ever horizontal well on the Vert La Gravelle field in France successfully completed in September 2019.
- Commenced the three well infill drilling program in Malaysia.
- Onion Lake Thermal F-Pad wells in Canada came on stream in September 2019.
- On track for 50,000 boepd 2019 exit rate with ongoing drilling activities in Canada, France and Malaysia.
- Operating costs[1] per boe of USD 13.0 for Q3 2019, in line with guidance.
- Capital expenditure budget remains in line with guidance of USD 188 million.

[1] *See definition on page 22 under "Non-IFRS measures"*

Financial Highlights

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2019**	2018	**2019**	2018
Revenue	131,437	106,746	408,214	342,545
Gross profit	23,487	37,060	109,659	120,553
Net result	6,330	26,487	65,216	74,298
Operating cash flow [1]	69,504	67,949	229,056	220,696
EBITDA [1]	68,885	66,240	225,160	206,009
Net Debt [1]	207,778	213,217	207,778	213,217

[1] *See definition on page 22 under "Non-IFRS measures"*

- Strong operating cash flow generation of USD 70 million in Q3 2019 (USD 229 million for the first nine months of 2019) at the upper end of guidance.
- Operating cash flows were utilised to fund capital expenditures and to reduce financial liabilities, with net debt decreasing from USD 277 million as at December 31, 2018 to USD 208 million as at September 30, 2019.

OPERATIONS REVIEW

Business Overview

Our focus since launching IPC in April 2017 remains unchanged: seeking to deliver operational excellence, demonstrating financial resilience, maximizing the value of our resource base and targeting growth organically and through acquisition.

Our vision and strategy from the outset was to use the IPC platform to build a new international upstream company focused on creating long-term value for our shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base.

With a strong set of third quarter results and activity levels peaking across all areas of operations, as well as the proposed launch of IPC's second share repurchase program, we continue to make excellent progress on all fronts in delivering on that strategy.

Delivering Operational Excellence
During Q3 2019, our assets delivered average daily net production of 45,500 boepd, in line with our latest Q2 guidance. Full year average production guidance is unchanged, expected at the lower end of the 46,000 to 50,000 boepd guidance range. The 2019 exit production rate expectation remains at 50,000 boepd.

The average production from the Suffield Assets in Canada of over 24,900 boepd during Q3 2019 was in line with our Q2 guidance. It is noteworthy that our first nine months 2019 average production levels at Suffield were three percent higher than 2018 levels demonstrating the positive impact of our ongoing oil drilling and gas optimization programs more than offsetting natural declines. Our N2N enhanced oil recovery (EOR) project and drilling program remain on schedule with the Alkaline Surfactant Polymer (ASP) plant ramp up ongoing and four out of a planned eight wells on production. In addition, work continued during Q3 2019 to mature additional drilling locations that could provide the optionality to continue with a single rig drilling program into 2020.

The average production from the Onion Lake Thermal facility during Q3 2019 was in line with our Q2 guidance at 10,000 boepd, a four percent increase on the second quarter. Facility optimization work has been completed that allowed for steam injection to commence at F-Pad during Q3 2019. We are already seeing the benefit of the increased steam injection rates and the start-up of production from the F-Pad wells during September 2019. As a result, we retain our expectation of exiting 2019 at approximately 12,000 boepd for Onion Lake Thermal.

In Malaysia, a world class uptime performance on the Bertam FPSO in excess of 99% continued during Q3 2019. Third quarter production on the Bertam field was 5,100 bopd, in line with our Q2 guidance and lower than the second quarter as a result of a planned shutdown for the rig to move onto the Bertam wellhead platform to commence infill drilling. The three well infill drilling program commenced in late August 2019. Following completion of the program, net Bertam production is expected to increase back above 7,500 bopd, a rate last achieved in July 2018.

Production in France was slightly ahead of our mid-point Q2 guidance during Q3 2019, averaging 2,500 boepd. In mid-September 2019, the first horizontal development well (VGR113) at the Vert La Gravelle field commenced production. Our development team was able to successfully deliver a 360 metre horizontal section in the west of the field. This was a major milestone for IPC, given that it was our first horizontal well drilled in France into a relatively thin Triassic reservoir. Initial indications of productivity from the well are ahead of expectation with rates in excess of 1,000 boepd. To put this in context, our entire Paris Basin production prior to the Vert La Gravelle redevelopment was around 2,000 boepd. We need now to understand what sustained production levels can be going forward, however we are certainly off to an encouraging start.

We are currently drilling the second well (VGR10), in the Southern part of the Vert La Gravelle field. Initially this well is expected to be completed as a vertical producer, with plans to later convert to water injection. This well is expected to provide important information regarding reservoir extent and quality in the Southern part of the field, where data is limited. This information is expected to be important for the potential second phase of development. Initial results are encouraging, having encountered the top structure shallow to prognosis. This could suggest a larger area above the oil water contact than previously mapped so our clear focus is now to understand the reservoir quality in the area. The initial results from the Vert La Gravelle redevelopment are positive, particularly when we consider that IPC holds around 7 MMboe of undeveloped 2C resources in similar Triassic reservoirs.

Our operating costs per boe for Q3 2019 was USD 13.0, in line with guidance. Full year capital expenditure guidance remains unchanged at USD 188 million.

Demonstrating Financial Resilience
IPC has continued to deliver a robust financial performance during Q3 2019 generating a quarterly operating cash flow of USD 70 million, at the upper end of guidance. This allowed IPC to fund its expenditure program and to reduce net debt from USD 239 million at the end of Q2 2019 to USD 208 million by the end of Q3 2019.

The strong operating cash flow generation is the result of good operational delivery combined with stronger realized oil and gas prices relative to forecast. The average Brent price of USD 62 per barrel during Q3 2019 was close to our mid-point guidance of USD 60 per barrel, however, the average WTI-WCS differential during Q3 2019 was USD 12 per barrel, better than our USD 15 per barrel upside case. Realized gas prices during Q3 2019 of CAD 2.23 per Mcf were marginally below our forecast of CAD 2.50 per Mcf.

Maximizing the Value of our Resource Base

Good progress has been made in adding value to IPC's resource base since April 2017. As at the end of December 2018, IPC's 2P reserves increased almost tenfold from inception to 288 MMboe. This included an excellent reserves replacement ratio of 103% in 2018, excluding acquisition additions, following the maturation of contingent resources from the infill drilling program in Malaysia into reserves as well as better reservoir performance and certain upgrades in France and Canada, particularly on the back of the gas optimization program in Canada.

2P net asset value per share increased by 37% in 2018 from USD 9.1 per share to USD 12.4 per share as at December 31, 2018.

In addition, we previously reported that our best estimate contingent resources as at the end of December 2018 increased to 849 MMboe (unrisked), after giving effect to the BlackPearl Acquisition. The largest single addition to the contingent resource base is the Blackrod project which has received regulatory approvals for Phase 1 of the development. A further addition of best estimate contingent resources (unrisked) of 243 MMboe was added to the contingent resources at Blackrod with a land acquisition completed in Q2 2019. We are confident that we have a solid contingent resource base in place to mature that can provide the feedstock to add significantly to reserves and to our value in the future.

Growth from Acquisition

IPC has transformed itself following the completion of two large acquisitions in 2018, and this third quarter 2019 report shows the material positive impact on reserves, resources, production, cash flow and net asset value per share.

With significant undrawn credit facilities at our disposal, we continue to opportunistically evaluate additional acquisition targets that we believe can deliver long-term value for our shareholders.

HSE Performance

Health, Safety & Environmental performance (HSE) 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 Q3 2019, IPC recorded no material safety or environmental incidents.

Share Repurchase Program

IPC's first share repurchase program was launched shortly after listing in May 2017. The Corporation acquired 25.5 million shares for USD 90 million under a tender offer at a time when we had 2P reserves of 29 MMboe, production of around 10,000 boepd and no contingent resources. The tender offer was made at CAD 4.77 per share, a significant discount to 2P net asset value.

Today IPC is trading at a wider discount to 2P net asset value, however production is expected to have increased five-fold to 50,000 boepd by the end of 2019 and reserves have increased ten-fold to 288 MMboe as at December 31, 2018. In addition, approximately 1 billion boe in contingent resources have been aggregated since the spin off. This robust value proposition combined with a year to date financial performance at the high end of our expectations and significant operating cash flow generation means that we have decided to return value to our shareholders by way of a share repurchase program.

We are today pleased to announce that we have sought approval from the TSX to commence a normal course issuer bid to repurchase IPC's common shares through the facilities of the TSX and Nasdaq Stockholm. The Board of Directors has approved, subject to acceptance by the TSX, the repurchase of up to approximately 11.5 million common shares, representing approximately 7% of IPC's outstanding common shares (or 10% of IPC's "public float" as at November 5, 2019), over a period of twelve months. IPC currently does not hold any common shares in treasury.

IPC has determined to implement the proposed share repurchase program because it believes that the current common share price does not reflect the underlying value of those shares. IPC believes that the share repurchase program represents an effective use of IPC's capital and an efficient way to return value to IPC's shareholders.

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

Operations Overview

Reserves and Resources

The IPC producing assets have more than doubled to 288 MMboe of 2P reserves as at December 31, 2018 (including the 2P reserves acquired in the BlackPearl Acquisition) compared to 129.1 MMboe of 2P reserves as at December 31, 2017, in each case as certified by independent third party reserves auditors. The reserves life index (RLI) as at December 31, 2018 (including the 2P reserves acquired in the BlackPearl Acquisition) was approximately 16 years. We previously reported that best estimate contingent resources as at December 31, 2018, increased thirteen fold to 849 MMboe (unrisked), including the best estimate contingent resources acquired in the BlackPearl Acquisition. With the land acquisition at the Blackrod project completed in Q2 2019, best estimate contingent resources as at December 31, 2018 have increased by a further 29% to 1,092 MMboe (unrisked).

IPC remains focused on organic growth and is maturing and executing opportunities across all our operated assets. In Canada, oil drilling activities commenced in late 2018 and continued through Q3 2019, and are complemented by gas optimization activities that continue to generate excellent production performance, offsetting the historical production decline. In Malaysia, the planned 2019 drilling program started in Q2 2019 with the three well infill drilling program commencing in late August 2019. In France, the Vert La Gravelle redevelopment project continued into 2019, with drilling operations starting as planned in Q2 2019 and continuing in Q3 2019.

Production

The average net production during Q3 2019 was in line with our latest Q2 guidance at 45.5 Mboepd, with all significant producing assets in line with or ahead of CMD expectations with the exception of Onion Lake Thermal in Canada. Production ramp up at Onion Lake Thermal was delayed on the back of the extreme cold weather in Q1 2019 and low water supply rates during the first half of 2019. Production from the first sustaining pad wells (F-Pad) commenced in Q3 2019 and the asset continues to ramp up through Q4 2019. The temporary production curtailment in the Paris Basin due to the Grandpuits refinery outage was resolved in early Q3 2019 and production was restored to full rates. The first well of the Vert La Gravelle redevelopment was drilled and brought online in Q3 2019 with initial production rates exceeding expectations.

Integration of the former BlackPearl assets has delivered a significant increase in production volumes for IPC relative to 2018 levels. The production during Q3 2019 with comparatives was comprised as follows:

Production in Mboepd	Three months ended September 30 2019	 2018	Nine months ended September 30 2019	 2018	Year ended December 31 2018
Crude oil					
Canada – Suffield	6.5	6.4	6.5	6.3	6.3
Canada – Onion Lake Thermal	10.0	–	9.8	–	–
Canada – Other	3.0	–	2.9	–	–
Malaysia	5.1	7.0	5.9	7.5	7.3
France	2.5	2.5	2.3	2.5	2.5
Total crude oil production	**27.1**	15.9	**27.4**	16.3	16.1
Gas					
Canada – Suffield	18.3	18.6	17.8	17.3	17.6
Canada – Other	0.1	–	0.1	–	–
Netherlands [1]	–	0.7	–	0.8	0.7
Total gas production	**18.4**	19.3	**17.9**	18.1	18.3
Total production	**45.5**	35.2	**45.3**	34.4	34.4
Quantity in MMboe	**4.18**	3.24	**12.37**	9.38	12.56

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

CANADA

Production in Mboepd	WI	Three months ended September 30 2019	Three months ended September 30 2018	Nine months ended September 30 2019	Nine months ended September 30 2018	Year ended December 31 2018
- Oil Suffield	100%	6.5	6.4	6.5	6.3	6.3
- Oil Onion Lake Thermal	100%	10.0	–	9.8	–	–
- Oil Other	50 - 100%	3.0	–	2.9	–	–
- Gas	99.7%[1]	18.4	18.6	17.9	17.3	17.6
Canada		**37.9**	25.0	**37.1**	23.6	23.9

[1] *On a well count basis.*

Production

Net production from the Canadian assets during Q3 2019 was in line with our latest Q2 guidance at 37.9 Mboepd. Strong production performance continued from both the Suffield Gas and Suffield Oil assets in Q3 2019, with the gas optimization program and the newly drilled oil wells driving Suffield performance to the top end of the CMD guidance range. Production performance from the Onion Lake Thermal asset is continuing to ramp up with first production now online from F-Pad wells. Production is expected to continue to ramp up during Q4 2019.

Organic Growth and Capital Projects

In Canada, IPC continues to carry out a full capital program including drilling, optimization and project work on all assets which remains in line with the capital guidance for 2019.

In Suffield Oil, at the end of Q3 2019, fifteen oil wells have been brought online with initial rates driving field performance to the high end of CMD guidance. The accelerated construction and start-up of the N2N EOR development project at Suffield commenced in Q2 2019, with four out of eight wells online, process start-up and first chemical injection from Q3 2019. The project is expected to deliver approximately 1,250 bopd of peak production to the Suffield Assets once fully ramped up in 2 to 3 years. In Suffield Gas, optimization activity continued in Q3 2019, with an extensive well swabbing program and execution of 75 well recompletions at the end of Q3 2019 with a further 75 recompletions planned for execution in Q4 2019.

Construction commenced on an increased permanent water supply system for Onion Lake Thermal in Q3 2019, with commissioning and start-up expected in Q4 2019. The project is expected to deliver sufficient water to fully supply production operations throughout all activity levels and seasonal weather conditions.

The planned three well drilling program commenced in John Lake in Q3 with first oil expected from all three wells in Q4 2019.

The third well pair at the BlackRod SAGD pilot project was completed in early Q3 2019 with steam start-up scheduled for early 2020.

MALAYSIA

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2019	2018	**2019**	2018	2018
Bertam	75%	**5.1**	7.0	**5.9**	7.5	7.3

Production
Net production from the Bertam field on Block PM307 during Q3 2019 was in line with our latest Q2 guidance at 5.1 Mboepd. Exceptional operational performance continued in Q3 2019 with facility uptime in excess of 99.9%.

Organic Growth
Following positive results from the 2016 and 2018 infill drilling programs and continued good reservoir performance, IPC has commenced the third phase of infill drilling on the Bertam field. The three well infill drilling program commenced in late August 2019. Following completion of the program, net Bertam production is expected to increase back above 7,500 bopd, a rate last achieved in July 2018.

As previously reported, the execution of two infill pilot holes was completed in Q3 2019 with better than expected results encountered in the A-15 area and poorer than expected results encountered in the A-14 area. As a result, the third infill well (A-20) location is planned to be in the A-15 area. The Keruing exploration well was also completed in Q3 2019 and encountered good quality reservoir at the targeted depth, however the well has been plugged and abandoned after the reservoir was found to be water-bearing.

EUROPE

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2019	2018	**2019**	2018	2018
France						
- Paris Basin	100% [1]	2.0	2.0	1.8	2.0	2.0
- Aquitaine	50%	0.5	0.5	0.5	0.5	0.5
Netherlands[2]	Various	–	0.7	–	0.8	0.7
		2.5	3.2	**2.3**	3.3	3.2

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

[2] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Production
Net production in France during Q3 2019 was slightly ahead of our latest Q2 guidance at 2.5 Mboepd due to flush production post the outage caused by the Grandpuit refinery outage in Q2 2019. The refinery was restarted during the early part of Q3 2019.

Organic Growth
IPC continues to work its undeveloped resource base in the Paris Basin. In parallel with the optimization of the Vert La Gravelle redevelopment project, a number of fields are undergoing study and planning work with the goal of maturing contingent resources into reserves.

The first phase of the Vert La Gravelle redevelopment, a three well program, commenced in Q2 2019. The first well in the program (VGR113H) was brought online in late Q3 2019 ahead of expectation. Drilling operations on Vert La Gravelle have continued into Q4 2019.

FINANCIAL REVIEW

Financial Results

The acquisition of BlackPearl was completed on December 14, 2018. For accounting purposes, the acquisition was reflected as at December 31, 2018 as the financial results from the acquired assets from the date of acquisition to December 31, 2018 were not material to the Group. The contribution of these assets is reported commencing from January 1, 2019.

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Revenue	**131.437**	129,357	147,420	111,898	106,746	120,637	115,162	54,647
Gross profit	**23,487**	39,287	46,885	26,311	37,060	45,920	37,573	13,471
Net result	**6,330**	25,744	33,142	29,346	26,487	21,498	26,313	8,977
Earnings per share – USD	**0.04**	0.16	0.20	0.29	0.30	0.24	0.30	0.10
Earnings per share fully diluted – USD	**0.04**	0.15	0.20	0.29	0.29	0.23	0.30	0.10
Operating cash flow [1]	**69,504**	76,496	83,056	58,322	67,949	76,687	76,060	37,156
EBITDA [1]	**68,885**	74,600	81,675	58,032	66,240	74,478	65,291	33,383
Net debt at period end [1, 2]	**207,778**	239,322	256,962	276,761	213,217	254,628	309,184	26,321

[1] *See definition on page 22 under "Non-IFRS measures".*

[2] *Net debt of USD 111,156 thousand was assumed from BlackPearl as at December 31, 2018.*

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2019	December 31, 2018
Non-current assets	1,213,066	1,200,035
Current assets	113,997	98,899
Total assets	**1,327,063**	1,298,934
Total non-current liabilities	449,581	506,832
Current liabilities	112,879	96,315
Total liabilities	**562,460**	587,296
Net assets	**764,603**	695,787
Working capital (including cash)	**1,118**	2,584

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) Suffield Assets, (ii) Onion Lake Thermal and (iii) other Canadian assets. This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – September 30, 2019						
USD Thousands	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Other	Total
Crude oil	29,824	34,889	9,335	28,680	20,117	–	**122,845**
NGLs	87	–	–	–	–	–	**87**
Gas	16,119	–	28	–	–	–	**16,147**
Net sales of oil and gas	**46,030**	**34,889**	**9,363**	**28,680**	**20,117**	**–**	**139,079**
Change in under/over lift position	–	–	–	–	(4,509)	–	**(4,509)**
Royalties	(1,889)	(3,535)	(1,630)	–	–	–	**(7,054)**
Hedging settlement	–	(488)	–	–	–	–	**(488)**
Other operating revenue	–	–	–	3,910	241	258	**4,409**
Revenue	**44,141**	**30,866**	**7,733**	**32,590**	**15,849**	**258**	**131,437**
Production costs	(25,453)	(10,324)	(6,099)	(9,627)	(8,777)	–	**(60,280)**
Depletion	(12,672)	(6,452)	(298)	(6,726)	(3,495)	–	**(29,643)**
Depreciation of other assets	–	–	–	(3,637)	–	–	**(3,637)**
Exploration and business development costs	–	–	–	(13,433)	–	(957)	**(14,390)**
Gross profit	**6,016**	**14,090**	**1,336**	**(833)**	**3,577**	**(699)**	**23,487**

	Three months ended – September 30, 2018					
USD Thousands	Canada – Suffield	Malaysia	France	Netherlands[1]	Other	Total
Crude oil	31,194	38,710	14,105	9	–	84,018
NGLs	112	–	–	71	–	183
Gas	16,899	–	–	3,091	–	19,990
Net sales of oil and gas	48,205	38,710`	14,105	3,171	–	104,191
Change in under/over lift position	–	–	215	(1)	–	214
Royalties	(2,392)	–	–	–	–	(2,392)
Other operating revenue	-	3,910	309	429	85	4,733
Revenue	45,813	42,620	14,629	3,599	85	106,749
Production costs	(28,276)	(2,408)	(5,426)	(1,702)	–	(37,812)
Depletion	(11,316)	(8,355)	(3,435)	(620)	–	(23,726)
Depreciation of other assets	–	(7,789)	–	–	–	(7,789)
Exploration and business development costs	–	(191)	–	–	(168)	(359)
Gross profit/(loss)	6,221	23,877	5,768	1,277	(83)	37,060

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

USD Thousands	Nine months ended – September 30, 2019						
	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Other	Total
Crude oil	95,993	104,850	27,626	93,171	39,065	–	**360,705**
NGLs	252	–	–	–	–	–	**252**
Gas	57,718	–	155	–	–	–	**57,873**
Net sales of oil and gas	**153,963**	**104,850**	**27,781**	**93,171**	**39,065**	**–**	**418,830**
Change in under/over lift position	–	–	–	–	787	–	**787**
Royalties	(5,759)	(10,713)	(4,832)	–	–	–	**(21,304)**
Hedging settlement	(374)	(2,494)	–	–	–	–	**(2,868)**
Other operating revenue	–	–	–	11,603	704	462	**12,769**
Revenue	**147,830**	**91,643**	**22,949**	**104,774**	**40,556**	**462**	**408,214**
Production costs	(82,081)	(33,551)	(17,420)	(21,092)	(21,305)	–	**(175,449)**
Depletion	(36,676)	(18,774)	(1,384)	(23,043)	(9,324)	–	**(89,201)**
Depreciation of other assets	–	–	–	(19,215)	–	–	**(19,215)**
Exploration and business development costs	–	–	(44)	(13,435)	–	(1,211)	**(14,690)**
Gross profit	**29,073**	**39,318**	**4,101**	**27,989**	**9,927**	**(749)**	**109,659**

USD Thousands	Nine months ended – September 30, 2018					
	Canada – Suffield	Malaysia	France	Netherlands[1]	Other	Total
Crude oil	92,691	133,079	49,338	55	–	275,163
NGLs	284	–	–	379	–	563
Gas	48,788	–	–	9,158	–	57,946
Net sales of oil and gas	141,763	133,079	49,338	9,492	–	333,672
Change in under/over lift position	–	–	386	11	–	397
Royalties	(5,737)	–	–	–	–	(5,737)
Other operating revenue	136	11,603	889	1,273	312	14,213
Revenue	136,162	144,682	50,613	10,776	312	342,545
Production costs	(85,399)	(14,242)	(22,329)	(5,076)	–	(127,046)
Depletion	(32,214)	(26,429)	(10,387)	(1,976)	–	(71,006)
Depreciation of other assets	–	(23,538)	–	–	–	(23,538)
Exploration and business development costs	–	(206)	–	–	(196)	(402)
Gross profit/(loss)	18,549	80,267	17,897	3,724	116	120,553

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Three and nine months ended September 30, 2019, Review

Revenue

Total revenue amounted to USD 131,437 thousand for Q3 2019 compared to USD 106,746 thousand for Q3 2018 and USD 408,214 thousand for the first nine months of 2019 compared to USD 342,545 thousand for the first nine months of 2018 and is analyzed as follows:

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2019**	2018	**2019**	2018
Crude oil sales	122,845	84,018	360,705	275,163
Gas and NGL sales	16,234	20,173	58,125	58,509
Change in under/overlift position	(4,509)	214	787	397
Royalties	(7,054)	(2,392)	(21,304)	(5,737)
Hedging settlement	(488)	–	(2,868)	–
Other operating revenue	4,409	4,733	12,769	14,213
Total revenue	**131,437**	106,746	**408,214**	342,545

The components of total revenue for the three and nine months ended September 30, 2019, and September 30, 2018, respectively are detailed below.

Crude oil sales

	Three months ended – September 30, 2019					
	Canada - Suffield	**Canada - Thermal**	**Canada - Other**	**Malaysia**	**France**	**Total**
Crude oil sales						
- Revenue in USD thousands	29,824	34,889	9,335	28,680	20,117	**122,845**
- Quantity sold in bbls	669,577	916,455	238,539	415,350	329,911	**2,569,832**
- Average price realized USD per bbl	44.54	38.07	39.13	69.05	60.98	**47.80**

	Three months ended – September 30, 2018				
	Canada - Suffield	**Malaysia**	**France**	**Netherlands[1]**	**Total**
Crude oil sales					
- Revenue in USD thousands	31,194	38,710	14,105	9	**84,018**
- Quantity sold in bbls	640,748	494,938	181,826	148	**1,317,660**
- Average price realized USD per bbl	48.68	78.21	77.58	49.49	**63.76**

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Despite lower oil prices, crude oil revenue was 46% higher for Q3 2019 compared to Q3 2018 mainly due to the contribution of the former BlackPearl assets in Canada from January 1, 2019. The sales volume in France was significantly higher in Q3 2019 compared to Q3 2018 mainly due to a cargo lifting of Aquitaine Basin crude, whilst there was lower sales volumes in Malaysia due to lower production volumes.

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. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q3 2019, WTI averaged USD 56 per bbl compared to USD 70 per bbl for Q3 2018 and the average discount from WTI to WCS used in our pricing formula was USD 12 per bbl compared to USD 22 per bbl for Q3 2018.

Onion Lake Thermal and other Canadian assets production is sold without being blended with condensate. It is heavier than the WCS quality and as a result trades at a discount to WCS prices.

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 62 per bbl for Q3 2019 compared to USD 75 per bbl for the comparative period in 2018.

	Nine months ended – September 30, 2019					
	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Total
Crude oil sales						
- Revenue in USD thousands	95,993	104,850	27,626	93,171	39,065	**360,705**
- Quantity sold in bbls	2,032,061	2,675,892	688,000	1,335,497	617,478	**7,348,928**
- Average price realized USD per bbl	47.24	39.18	40.15	69.76	63.26	**49.08**

	Nine months ended – September 30, 2018				
	Canada - Suffield	Malaysia	France	Netherlands[1]	Total
Crude oil sales					
- Revenue in USD thousands	92,691	133,079	49,339	55	275,163
- Quantity sold in bbls	1,999,498	1,761,331	685,478	909	4,447,216
- Average price realized USD per bbl	46.36	75.56	71.98	60.69	61.87

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Crude oil sales were 31 percent higher for the first nine months of 2019 compared to the first nine months of 2018 mainly due to the contribution of the former BlackPearl assets in Canada from January 1, 2019, partly offset by lower sales volumes in Malaysia due to lower production volumes, and lower sales volumes in France due to the refinery shut-in during Q2 2019.

The Canadian realized sales price is based on the WCS price which is traded at a discount to WTI. WTI averaged USD 57 per bbl and the average discount from WTI to WCS was approximately USD 12 per bbl for the first nine months of 2019, compared to an average WTI of USD 61 per bbl and an average discount from WTI to WCS of USD 16 per bbl for the comparative period in 2018.

All sales and expenses from the Blackrod asset SAGD pilot evaluation are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. The Blackrod asset sales volume and revenue are therefore not included in the crude oil sales tables above. Revenue from the Blackrod asset amounted to USD 3,386 thousand for the first nine months of 2019.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average Dated Brent crude oil price was USD 65 per bbl in the first nine months of 2019 compared to USD 72 per bbl for the comparative period in 2018.

Gas and NGL sales

	Three months ended – September 30, 2019		
	Canada - Suffield	Canada - Other	Total
Gas and NGL sales			
- Revenue in USD thousands	16,206	28	**16,234**
- Quantity sold in Mcf	9,511,929	53,403	**9,565,332**
- Average price realized USD per Mcf	1.70	0.53	**1.70**

	Three months ended – September 30, 2018		
	Canada - Suffield	**Netherlands[1]**	**Total**
Gas and NGL sales			
- Revenue in USD thousands	17,011	3,162	20,173
- Quantity sold in Mcf	9,653,287	391,120	10,044,407
- Average price realized USD per Mcf	1.76	8.08	2.01

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Gas and NGL sales revenue was 20% lower for Q3 2019 compared to Q3 2018 mainly due to the sale of the Netherlands business in December 2018. 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 Q3 2019, IPC realized an average price of CAD 2.23 per Mcf which was above Empress average pricing for Q3 2019 of CAD 2.04 per Mcf, as a result of forward sales contracts entered into for Q3 2019.

	Nine months ended – September 30, 2019		
	Canada - Suffield	**Canada – Other**	**Total**
Gas and NGL sales			
- Revenue in USD thousands	57,970	155	**58,125**
- Quantity sold in Mcf	27,471,424	158,952	**27,630,376**
- Average price realized USD per Mcf	2.11	0.98	**2.10**

	Nine months ended – September 30, 2018		
	Canada - Suffield	**Netherlands[1]**	**Total**
Gas and NGL sales			
- Revenue in USD thousands	49,072	9,437	58,509
- Quantity sold in Mcf	26,732,084	1,296,027	28,028,111
- Average price realized USD per Mcf	1.84	7.28	2.09

[1] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

In Canada, gas and NGL sales revenue was 18% higher during the first nine months of 2019 compared to the first nine months of 2018 due to higher sales volumes sold and higher gas prices achieved. For the nine months ended 2019, IPC realized an average price of CAD 2.79 per Mcf compared to CAD 2.35 per Mcf for the first nine months of 2018.

Hedging settlement

IPC entered into risk management contracts in order to comply with the covenants of a financing facility arrangement that was repaid and terminated during Q2 2019. The hedges are mainly oil price swaps and collars to manage pricing exposure. IPC 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. No new hedging contracts were entered into during Q3 2019 and IPC no longer has any hedging requirements under its financing facilities. The realized hedging settlements for Q3 2019 amounted to a loss of USD 488 thousand and for the first nine months of 2019, amounted to a loss of USD 2,868 thousand. Also see the Financial Risk Management section below.

Other operating revenue

Other operating revenue amounted to USD 4,409 thousand for Q3 2019 compared to USD 4,733 thousand for Q3 2018 and USD 12,769 thousand for the first nine months of 2019 compared to USD 14,213 thousand for the first nine months of 2018. 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. The reduction in other operating revenue in Q3 2019 compared to Q3 2018 is mainly due to the reduction in tariff income following the sale of the gas assets in the Netherlands in December 2018.

Production costs

Production costs including inventory movements amounted to USD 60,280 thousand for Q3 2019 compared to USD 37,812 thousand for Q3 2018 and USD 175,449 thousand for the first nine months of 2019 compared to USD 127,046 thousand for the first nine months of 2018 and is analyzed as follows:

USD Thousands	Three months ended – September 30, 2019						
	Canada - Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Other[3]	Total
Operating costs[1]	20,888	10,324	6,099	21,420	7,500	(11,730)	54,501
USD/boe[2]	9.18	11.26	21.41	45.42	32.63	n/a	13.05
Cost of blending	5,088	–	–	–	–	–	5,088
Change in inventory position	(523)	–	–	(63)	1,277	–	**691**
Production costs	25,453	10,324	6,099	21,357	8,777	**(11,730)**	**60,280**

USD Thousands	Three months ended – September 30, 2018					
	Canada - Suffield	Malaysia	France	Netherlands[4]	Other [3]	Total
Operating costs[1]	22,633	19,123	7,214	1,702	(11,730)	38,942
USD/boe[2]	9.87	29.62	30.99	26.07	n/a	12.03
Cost of blending	5,689	_	_	_	_	5,689
Change in inventory position	(46)	(4,985)	(1,788)	–	–	(6,819)
Production costs	28,276	14,138	5,426	1,702	(11,730)	37,812

USD Thousands	Nine months ended – September 30, 2019						
	Canada - Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Other[3]	Total
Operating costs[1]	65,803	33,551	17,420	57,282	21,005	(34,808)	**160,253**
USD/boe[2]	9.93	12.54	21.12	35.45	33.60	n/a	**12.96**
Cost of blending	16,850	–	–	–	–	–	**16,850**
Change in inventory position	(572)	–	–	(1,382)	300	–	**(1,654)**
Production costs	**82,081**	**33,551**	**17,420**	**55,900**	**21,305**	**(34,808)**	**175,449**

USD Thousands	Nine months ended – September 30, 2018					
	Canada - Suffield	**Malaysia**	**France**	**Netherlands[4]**	**Other[3]**	**Total**
Operating costs[1]	66,754	54,323	22,347	5,076	(34,808)	113,692
USD/boe[2]	10.37	26.60	32.86	23.37	n/a	12.12
Cost of blending	19,834	–	–	–	–	19,834
Change in inventory position	(1,189)	(5,273)	(18)	–	–	(6,480)
Production costs	85,399	49,050	22,329	5,076	(34,808)	127,046

[1] *See definition on page 22 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 20.55 and USD 11.45 for Q3 2019 and Q3 2018, respectively, and USD 13.91 and USD 9.55 for the nine months ended September 30, 2019, and September 30, 2018, respectively.*

[4] *On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

Operating costs

Operating costs amounted to USD 54,501 thousand for Q3 2019 compared to USD 38,942 thousand for Q3 2018 and USD 160,253 thousand for the first nine months of 2019 compared to USD 113,692 thousand for the first nine months of 2018. The increase in operating costs is mainly due to the contribution of the former BlackPearl assets in Canada. Operating costs per boe amounted to USD 13.05 per boe in Q3 2019 compared with USD 12.03 per boe in Q3 2018 and is in line with CMD guidance for Q3 2019. The operating costs per boe increased in Malaysia for Q3 2019 compared to Q3 2018 due to lower production as well as costs associated with a workover of a well.

The full year operating costs guidance remains unchanged at USD 12.90 per boe.

Cost of blending

For the Suffield Assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 5,088 thousand for Q3 2019 compared to USD 5,689 thousand for Q3 2018 and USD 16,850 thousand for the first nine months of 2019 compared to USD 19,834 thousand for the first nine months of 2018. As a result of the blending, actual sales volumes are higher than produced barrels. A cost of USD 691 thousand and USD 213 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q3 2019 and Q3 2018, respectively, and USD 1,844 thousand and USD 979 thousand for the nine months ended September 30, 2019, and September 30, 2018, respectively.

Change in inventory position

The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion and market value and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. At the end of Q3 2019, IPC had crude entitlement of 160,000 barrels of oil on the FPSO Bertam facility.

In the Aquitaine Basin, France, there was one cargo lifting in the first nine months of 2019 in Q3 2019 compared to one cargo lifting in the comparative period in 2018 in Q1 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 29,643 thousand for Q3 2019 compared to USD 23,726 thousand for Q3 2018 and USD 89,201 thousand for the first nine months of 2019 compared to USD 71,006 thousand for the first nine months of 2018. The depletion charge is analyzed in the following tables:

	Three months ended – September 30, 2019					
	Canada – Suffield	**Canada – Thermal**	**Canada – Other**	**Malaysia**	**France**	**Total**
Depletion cost in USD thousands	12,672	6,452	298	6,726	3,495	**29,643**
USD per boe	5.57	7.04	1.05	14.26	15.21	**7.10**

	Three months ended – September 30, 2018				
	Canada – Suffield	**Malaysia**	**France**	**Netherlands[1]**	**Total**
Depletion cost in USD thousands	11,316	8,355	3,435	620	23,726
USD per boe	4.93	12.94	14.76	9.49	7.33

[1]*On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

	Nine months ended – September 30, 2019					
	Canada – Suffield	**Canada – Thermal**	**Canada – Other**	**Malaysia**	**France**	**Total**
Depletion cost in USD thousands	36,676	18,774	1,384	23,043	9,324	**89,201**
USD per boe	5.54	7.02	1.68	14.26	14.91	**7.21**

	Nine months ended – September 30, 2018				
	Canada – Suffield	**Malaysia**	**France**	**Netherlands[1]**	**Total**
Depletion cost in USD thousands	32,214	26,429	10,387	1,976	71,006
USD per boe	5.00	12.94	15.27	9.10	7.57

[1]*On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands.*

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 3,637 thousand for Q3 2019 compared to USD 7,789 thousand for Q3 2018 and USD 19,215 thousand for the first nine months of 2019 compared to USD 23,538 thousand for the first nine months of 2018. 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.

Exploration and business development costs

The total exploration and business developments costs amounted to USD 14,390 thousand for Q3 2019 and USD 14,690 thousand for the first nine months of 2019. The Q3 costs mainly related to unsuccessful drilling in Malaysia on the Keruing exploration prospect and the infill pilot well in the A-14 area.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 2,699 thousand for Q3 2019 compared to USD 2,835 thousand for Q3 2018 and USD 8,724 thousand for the first nine months of 2019 compared to USD 9,912 thousand for the first nine months of 2018.

Net financial items

Net financial items for Q3 2019 amounted to USD 11,224 thousand compared to USD 3,291 thousand for Q3 2018 and included a largely non-cash net foreign exchange loss of USD 4,677 thousand for Q3 2019 compared to a net foreign exchange gain of USD 3,418 thousand in Q3 2018. 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 USD 6,547 thousand for Q3 2019, compared to USD 6,709 thousand for Q3 2018. The interest expense for Q3 2019 amounted to USD 2,988 thousand compared to USD 3,447 thousand for Q3 2018. The unwinding of the asset retirement obligation discount rate amounted to USD 2,668 thousand for Q3 2019 compared to USD 2,306 thousand for Q3 2018.

Net financial items for the first nine months of 2019 amounted to USD 21,455 thousand compared to USD 27,492 thousand for the first nine months of 2018 and included a largely non-cash net foreign exchange gain of USD 4,182 thousand for the first nine months of 2019 compared to a net foreign exchange loss of USD 6,176 thousand for the first nine months of 2018 mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to USD 25,637 thousand for the first nine months of 2019 compared to USD 21,316 thousand for the first nine months of 2018. The interest expense amounted to USD 14,559 thousand for the first nine months of 2019 compared to USD 11,820 thousand for the comparative period and included a make-whole expense for the senior notes which were redeemed early as part of the Canadian refinancing during Q2 2019. The unwinding of the asset retirement obligation discount rate amounted to USD 7,985 thousand for the first nine months of 2019 compared to USD 7,035 thousand for the first nine months of 2018 and the increase is due to the inclusion of the former BlackPearl asset retirement obligation at the year-end partly offset by the removal of the unwinding expense following the sale of the assets in the Netherlands in December 2018.

Income tax

The corporate income tax charge for Q3 2019 amounted to USD 3,234 thousand compared to a charge of USD 4,447 thousand for Q3 2018 and a charge of USD 14,264 thousand for the first nine months of 2019 compared to USD 8,851 thousand for the first nine months of 2018. There was a current tax credit of USD 7,196 thousand in Q1 2018 largely related to a non-recurring Dutch petroleum tax refund relating to historical intragroup charges and an industry change in the calculation of the present value of the asset retirement obligation.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first nine months of 2019 was as follows:

USD Thousands	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Development	28,084	17,098	4,131	14,511	24,092	**87,916**
Exploration and evaluation	–	–	9,798	16,304	98	**26,200**
	28,084	17,098	13,929	30,815	24,190	**114,116**

Capital expenditure of USD 114,116 thousand was mainly spent on drilling on the Suffield Assets, Onion Lake Thermal facilities and the commencement in Q2 2019 of the drilling campaign in Malaysia and the Vert La Gravelle redevelopment in France. In addition, the acquisition costs of the land and contingent resource position adjacent to the Blackrod property are reflected under Canada – Other exploration and evaluation costs. The guidance for the full year 2019 remains unchanged at USD 188 million with significant capital investment planned in all areas of activity during the fourth quarter of 2019.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 71,783 thousand as at September 30, 2019, which included USD 68,369 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.

Acquisition of BlackPearl

On December 14, 2018, IPC completed the BlackPearl Acquisition for total consideration of USD 288,643 thousand. The purchase price has been allocated, on a preliminary basis, as follows:

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

USD Thousands	
Cash and cash equivalents	2,572
Trade and other receivables	883
Inventory	42
Prepaid expenses and deposits	882
Fair value of risk management assets	13,909
Deferred tax assets	69,592
Property, plant and equipment	370,647
Other fixed assets	1,037
Accounts payable and accrued liabilities	(16,587)
Fair value of risk management liabilities	(1,564)
Decommissioning liabilities	(28,708)
Long-term debt	(113,728)
Other provisions	(1,321)
MTM reserve in equity	(9,013)
Total Consideration	**288,643**
Settled by:	
Equity instruments (75,798,219 common shares of IPC)	**288,643**

Acquisition-related costs of approximately USD 2.3 million have been recognized in the income statement for the year ended December 31, 2018. No material acquisition-related costs were recognized in the first nine months of 2019.

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

Financial Position and Liquidity

Financing

In connection with the completion of the Suffield acquisition in January 2018, the Group entered into an amendment to its reserve-based lending credit facility to increase such facility from USD 100 million to USD 200 million and to extend the maturity to end June 2022. Concurrently, IPC Alberta Ltd entered into a CAD 250 million reserve-based lending credit facility and a CAD 60 million second lien facility in Canada in January 2018.

In August 2018, the Group fully repaid and cancelled the Canadian second lien CAD 60 million loan facility.

In December 2018, in connection with the completion of the BlackPearl Acquisition, the Group assumed the debt of BlackPearl consisting of a reserve-based lending credit facility of CAD 120 million and senior secured notes outstanding of CAD 75 million. The reserve-based lending facility had a maturity date in May 2021 and the senior secured notes had a maturity date in June 2020.

Effective as of June 1, 2019, IPC Alberta Ltd. and BlackPearl amalgamated into IPC Canada Ltd., which is a wholly-owned subsidiary of IPC. At the same time, the reserve-based lending credit facilities of IPC Alberta and BlackPearl were combined into one reserve-based lending credit facility of IPC Canada in the amount of CAD 375 million. The IPC Canada reserve-based credit lending facility has a maturity date in May 2021. The senior secured notes of BlackPearl of CAD 75 million were fully repaid and cancelled in June 2019, from a drawdown under the CAD 375 million reserve-based lending credit facility.

The borrowing base availability under the Group's reserve-based lending credit facility is currently USD 150 million of which USD 51 million was outstanding as at September 30, 2019. The borrowing base availability of IPC Canada's reserve-based lending credit facility is currently CAD 375 million of which CAD 226 million was outstanding as at September 30, 2019.

Total net debt as at September 30, 2019, amounted to USD 208 million.

The Group expects to fully fund the remaining proposed 2019 capital program and any shares that may be purchased under the share repurchase program from its operating cash flows and available credit facilities.

The Group is in full compliance with the covenants under the credit facilities, which are customary for the size and nature of such facilities.

Cash and cash equivalents held amounted to USD 13,811 thousand as at September 30, 2019. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at September 30, 2019, the Group had a net working capital balance including cash of USD 1,118 thousand compared to USD 2,584 thousand as at December 31, 2018. The net working capital balance including cash at June 30, 2019 was USD 17,752 thousand, and the significant reduction in the position in Q3 2019 is mainly due to the increased trade and other payables position – see Note 19 of the interim condensed consolidated Financial Statements.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating 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. 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.

"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. "Net cash" is cash and cash equivalents less bank loans.

Reconciliation of Non-IFRS Measures

Operating cash flow
The following table sets out how operating cash flow is calculated from figures shown in the interim condensed consolidated financial statements:

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2019**	2018	**2019**	2018
Revenue	131,437	106,746	408,214	342,545
Production costs	(60,280)	(37,812)	(175,449)	(127,046)
Current tax	(1,653)	(985)	(3,709)	5,197
Operating cash flow	**69,504**	67,949	**229,056**	220,696

EBITDA

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2019**	2018	**2019**	2018
Net result	6,330	26,487	65,216	74,298
Net financial items	11,224	3,291	21,455	27,492
Income tax	3,234	4,447	14,264	8,851
Depletion	29,643	23,726	89,201	71,006
Depreciation of other assets	3,637	7,789	19,215	23,538
Exploration and business development costs	14,390	359	14,690	402
Depreciation included in general, administration and depreciation expenses [1]	427	141	1,119	422
EBITDA	**68,885**	66,240	**225,160**	206,009

[1] *Item is not shown in the interim condensed consolidated financial statements*

Operating costs

The following table sets out how operating costs is calculated:

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2019**	2018	**2019**	2018
Production costs	60,280	37,812	175,449	127,046
Cost of blending[1]	(5,088)	(5,689)	(16,850)	(19,834)
Change in inventory position	(691)	6,819	1,654	6,480
Operating costs	**54,501**	38,942	**160,253**	113,692

[1] *Item is not shown in the consolidated financial statements. See production costs section above.*

Net debt

The following table sets out how net debt is calculated from figures shown in the interim condensed consolidated financial statements:

USD Thousands	**September 30, 2019**	December 31, 2018
Bank loans	221,589	232,357
Senior secured notes	–	55,030
Cash and cash equivalents	(13,811)	(10,626)
Net debt	**207,778**	276,761

Off-Balance Sheet Arrangements

On May 1, 2018, IPC, through its subsidiary IPC Canada Ltd (then known as IPC Alberta Ltd.), had issued a letter of credit for an amount of CAD 4 million in respect of its obligations to purchase diluent. This letter of credit is still outstanding.

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

Outstanding Share Data

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

As at January 1, 2018, the total number of common shares issued and outstanding in IPC was 87,921,846. In connection with the completion of the BlackPearl Acquisition, IPC issued a total of 75,798,219 common shares to the former shareholders of BlackPearl. As at November 5, 2019, IPC has a total of 163,720,065 common shares issued and outstanding with no par value.

Nemesia S.à.r.l., Lorito Holdings S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 38,053,757 common shares in IPC, representing 23.2% of the outstanding common shares.

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 1,810,566 stock options and 2,306,493 IPC Performance and Restricted Share Plan awards (638,519 awards granted in July 2018, 314,528 awards granted in March 2019 and 1,353,446 awards granted in July 2019), outstanding as at November 5, 2019.

Contractual Obligations and Commitments

As part of the acquisition of the Suffield Assets, the Group is required to pay Cenovus Energy Inc. additional cash consideration dependent upon the future prices of oil and natural gas for each month between January 2018 and December 2019. A total estimated contingent consideration of CAD 10,371 thousand (USD 7,828 thousand) has been reflected in the Financial Statements. Of this amount, the contingent consideration paid in 2018 and during the first nine months of 2019 amounted to CAD 7,192 thousand (USD 5,429 thousand) in total, being CAD 5,189 thousand (USD 3,917 thousand) for oil and CAD 2,003 thousand (USD 1,512 thousand) for gas. The maximum undiscounted amount of all future payments that the Group could be required to pay from October 1 to December 31, 2019, is up to CAD 4.5 million (USD 3.5 million).

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 18 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

As a result of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum. The final settlement of USD 14 million was paid in June 2019 and no further amounts are outstanding to Lundin Petroleum in respect of the working capital.

Lundin Petroleum has charged the Group USD 532 thousand in respect of office space rental and USD 1,330 thousand in respect of shared services provided during the first nine months of 2019.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at September 30, 2019, 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.

The Group had gas price purchase hedges outstanding as at September 30, 2019, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Basis	Average Pricing
Gas Purchase			
October 1, 2019 – December 31, 2019	10,000	AECO 5a	CAD 1.57/GJ
January 1, 2020 – December 31, 2020	4,000	AECO 5a	CAD 1.49/GJ

The Group had oil price sales hedges outstanding as at September 30, 2019, which are summarized as follows:

Period	Volume (barrels per day)	Weighted Average Floor (WTI in USD)	Weighted Average Cap (WTI in USD)
Oil Sales			
October 1, 2019 – December 31, 2019	3,000	49.45	68.15
January 1, 2020 – March 31, 2020	3,500	50.00	77.50
April 1, 2020 – June 30, 2020	6,150	35.00	71.74

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 fair value net asset of USD 1,644 thousand at September 30, 2019.

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, 2018 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.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three month period ended September 30, 2019, 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).

Acquisition of BlackPearl

The BlackPearl Acquisition was completed less than 365 days from the end of the current financial period. As such, under applicable Canadian reporting requirements, the Group is not required to and is not certifying as to the design and operating effectiveness of disclosure controls and procedures and internal controls over financial reporting in respect of these assets.

Summary financial information related to BlackPearl is presented above in the Capital Expenditure section.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "forecast", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".

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

- our intention and ability to continue to implement our strategies to build long-term shareholder value;
- our intention to review future potential growth opportunities;
- the ability of our portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the continued facility uptime and reservoir performance in our areas of operation;
- the completion of the Vert La Gravelle redevelopment project, including drilling and related production rates and the ability to gather further information regarding the southern part of the field, and other organic growth opportunities in France;
- the completion of the third phase of infill drilling in Malaysia and the ability to identify and mature additional locations, and the production uplift from such drilling;
- future development potential of the Suffield operations, including continued and future oil drilling and gas optimization programs, the ability to offset natural declines and the N2N EOR development project (including estimated peak rates and timing of such project);
- the proposed further conventional oil drilling in Canada, including the ability of such drilling to identify further drilling or development opportunities;
- development of the Blackrod project in Canada;
- the results of the facility optimization program, the work to debottleneck the facilities and injection capability and the F-Pad production, as well as water intake and steam generation issues, at Onion Lake Thermal;
- the intention to commence a share repurchase program, including the acceptance thereof by the TSX;
- the ability to IPC to acquire common shares under the proposed share repurchase program, including the timing of any such purchases;
- the return of value to IPC's shareholders as a result of the share repurchases program;
- 2019 production range, exit rate, operating costs and capital expenditure estimates;
- potential further acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- estimates of prospective resources;
- the ability to generate cash flows and use that cash to repay debt and to continue to deleverage; and
- future drilling and other exploration and development activities.

Statements relating to "reserves", "contingent resources" and "prospective 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, labor 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 and exchange rate fluctuations;
- interest 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.

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, 2018 (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.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in the Suffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), 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 McDaniel's January 1, 2019, price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in the Onion Lake, Blackrod and Mooney areas of Canada are effective as of December 31, 2018, and are included in reports prepared by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2019, price forecasts.

Reserve estimates, contingent resource estimates, prospective 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, 2018, 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 McDaniel's January 1, 2019, price forecasts.

The price forecasts used in the reserve reports are available on the website of McDaniel (www.mcdan.com), and are contained in the AIF.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 288 MMboe as at December 31, 2018, by the mid-point of the initial 2019 production guidance of 46,000 to 50,000 boepd. The reserves replacement ratio is based on 2P reserves of 129.1 MMboe as at December 31, 2017 (including the 2P reserves attributable to the acquisition of the Suffield area assets which completed on January 5, 2018), production during 2018 of 12.4 MMboe, additions to 2P reserves during 2018 of 12.7 MMboe and 2P reserves of 128.0 MMboe as at December 31, 2018 (excluding the 2P reserves attributable to the BlackPearl Acquisition which completed on December 14, 2018).

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. "Possible reserves" are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible 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.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Chance of discovery is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. There is no certainty that any portion of the prospective resources estimated in the report audited by ERCE and summarized in this MD&A will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources audited. Estimates of the prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated in the report audited by ERCE and summarized in this MD&A cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates in the report audited by ERCE and summarized in this MD&A.

Reserves and contingent resources included in the reports prepared by McDaniel, Sproule and ERCE, as applicable, have been aggregated in this document 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". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "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.

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
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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