Q4

International Petroleum Corporation

Management's Discussion and Analysis

For the three months ended and year ended December 31, 2018

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 21.

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 33.

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 the report 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 February 12, 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 audited consolidated financial statements and accompanying notes for the year ended December 31, 2018 ("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"). Upon completion of the BlackPearl Acquisition, BlackPearl became a wholly-owned subsidiary of IPC.

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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Prior to the Spin-Off date, separate financial statements were not prepared for the assets that were spun-off as they were not operated as a single business by Lundin Petroleum and accordingly, the results up until the Spin-Off date have been carved out from the historical consolidated financial statements of Lundin Petroleum. Refer to the Financial Statements for additional information on the basis of preparation.

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

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

	December 31, 2018		December 31, 2017	
	Average	Period end	Average	Period end
1 EUR equals USD	1.1815	1.1450	1.1293	1.1993
1 USD equals CAD	1.2958	1.3629	1.2982	1.2540
1 USD equals MYR	4.0354	4.1325	4.2994	4.0470

2018 HIGHLIGHTS

Business Development

- Acquisition of conventional oil and gas assets in the Suffield area (the "Suffield Assets") of southern Alberta, Canada completed on January 5, 2018.
- Acquisition of BlackPearl Resources Inc. ("BlackPearl") completed on December 14, 2018.
- Disposal of all IPC upstream assets in the Netherlands in December 2018.

Operational and Resource Highlights

- Average net production of 34,600 barrels of oil equivalent (boe) per day (boepd) for the fourth quarter of 2018, above the high end of the guidance range with strong performance from all assets.
- Full year 2018 average net production above the high end of the guidance range at 34,400 boepd (revised guidance 32,500 to 34,000 boepd).
- Successfully executed the enhanced gas optimization program and commenced oil drilling in Canada.
- Infill well performance in Malaysia and gas optimization activities in Canada outperformed expectation during 2018.
- Greater than 100% 2P reserves replacement ratio in 2018 (excluding the 2P reserves acquired in the BlackPearl Acquisition) with 2P reserves more than doubled to 288 MMboe as at end December 2018 (including the 2P reserves acquired in the BlackPearl Acquisition) compared to end December 2017.
- Thirteen fold increase in best estimate contingent resources (unrisked) to 849 MMboe as at end December 2018 (including the best estimate contingent resources acquired in the BlackPearl Acquisition) compared to end December 2017.
- Operating costs[1] per boe of USD 12.4 for the full year 2018, lower than the 2018 CMD guidance (12.6 USD per boe).
- 2018 capital expenditure of USD 39.0 million compared to Q3 guidance of USD 44 million.
- Sanctioned a third phase of infill drilling in Malaysia for 2019 execution.
- Sanctioned the Vert La Gravelle development in France for 2019 execution.

[1] *See definition on page 21 under "Non-IFRS measures"*

Financial Highlights

The acquisition of BlackPearl was completed on December 14, 2018. For accounting purposes, the acquisition was reflected on the balance sheet as at December 31, 2018. Given that the financial and operational 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 not reported in 2018 and will only be reported from January 1, 2019.

	Three months ended December 31		Year ended December 31	
USD Thousands	**2018**	2017	**2018**	2017
Revenue	111,898	54,647	454,443	203,001
Gross profit	26,311	13,471	146,864	48,758
Net result	29,346	8,977	103,644	22,723
Operating cash flow [1]	58,322	37,156	279,018	138,368
EBITDA [1]	58,032	33,383	264,041	129,259
Net Debt [1] (including assumed Net Debt from BlackPearl at December 31, 2018)	276,761	26,321	276,761	26,321

[1] *See definition on page 21 under "Non-IFRS measures"*

- Full year operating cash flow generation of USD 279 million, up over 100% compared to the prior year following the acquisition of the Suffield Assets and higher oil prices.
- Excluding assumed debt from the BlackPearl Acquisition, net debt reduced by approximately USD 190 million to USD 166 million as at December 31, 2018, from USD 355 million at the completion of the acquisition of the Suffield Assets on January 5, 2018. Including the assumed debt from the BlackPearl Acquisition, total net debt of the Group is USD 277 million as at December 31, 2018.

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 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 our fourth quarter performance delivered ahead of guidance and another transformational acquisition completed in December 2018, we continue to make excellent progress on all fronts in delivering on that strategy.

Delivering Operational Excellence
During the fourth quarter of 2018 our assets delivered average daily net production of 34,600 boepd which was above the high end of our revised guidance for the quarter. The fourth quarter performance concludes an excellent year of delivery from all assets with full year average daily net production of 34,400 boepd coming in above the high end of our original full year guidance (30,000 to 34,000 boepd).

Production from the Suffield Assets in Canada of almost 24,900 boepd during the fourth quarter of 2018 was ahead of expectation and more than 9 percent above our first half production, driven mainly by excellent facility uptime performance and the successful delivery of gas optimization activities.

A world class uptime performance on the Bertam FPSO in excess of 99 percent continued during the fourth quarter of 2018. Fourth quarter production on the Bertam field was 6,800 bopd, with full year production amounting to 7,300 bopd. Continued strong reservoir performance from the A-16 and A-17 infill wells drilled during the first quarter in addition to the A-15 infill well drilled in 2016 meant that the Bertam field was able to deliver an impressive 9% increase in production relative to 2017.

Production in France was at the high end of our expectation driven by good performance at a number of our Paris Basin and Aquitaine fields.

Our operating costs per boe for the fourth quarter was USD 13.1, resulting in a full year average operating cost per boe of USD 12.4, below our guidance of USD 12.6.

Our full year capital expenditure of USD 39.0 was below our latest guidance of USD 44.0 million, mainly driven by re-phasing of certain expenditure into 2019.

Demonstrating Financial Resilience
IPC has continued to deliver a robust financial performance during the fourth quarter of 2018 generating operating cash flow of USD 58 million. This allowed IPC to fund its expenditure program and reduce net debt from USD 213 million at the end of the third quarter to USD 166 million by the end of the fourth quarter. Full year operating cash flow was in excess of USD 279 million and net debt reduction was close USD 190 million since completion of the Suffield acquisition in early January 2018. Including the additional USD 111 million of net debt acquired as part of the acquisition of BlackPearl, IPC's total year end net debt was USD 277 million.

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 end December 2017, IPC's 2P reserves had more than quadrupled to 129.1 MMboe (including 2P reserves attributable to the Suffield Assets). This included a reserves replacement ratio of 76 percent during 2017 for the non-Canadian assets.

In Malaysia, following positive results from the 2016 and 2018 infill drilling programs and continued good reservoir performance, we were encouraged to mature a third phase of infill drilling on the Bertam field for execution in 2019. Up to three drilling locations have been identified and work continues to mature additional locations. In addition, we plan to drill the Keruing prospect during the first half of 2019. Petronas approval has been received and rig contracting is being finalized. This will allow us to combine drilling Keruing with a pilot well in the A-14 location to de-risk the third phase infill drilling program expected later in 2019.

In Canada during the fourth quarter of 2018, oil drilling commenced for the first time since 2014 on the Suffield Asset. Five horizontal wells had been drilled by the end of the fourth quarter with production commencing in January 2019. Initial rates are in line with expectations. Approvals are in place for continuous drilling through 2019, with work ongoing to mature a 2020 drilling program. On the gas side, given the exceptional results from the 2018 gas optimization program, further work is expected to continue through 2019 to unlock identified potential.

In early December 2018, the Government of Alberta took the dramatic decision to curtail production levels by 325,000 bopd (8.7% of production). The aim was to reduce stock levels and rebalance markets so that heavy crude oil price differentials (WTI-WCS), which came under huge pressure during the fourth quarter, could return to more normalized levels. IPC is not affected by the production curtailments but has benefitted from the sharp improvements in the differential witnessed since the policy was announced. Following an immediate reduction in crude stock levels in January, production curtailments will be eased by 75,000 bopd in February and March and monitored month by month for the remainder of 2019 with the objective of phasing out the cuts when additional pipeline capacity from Enbridge's Line 3 is reported to come on-stream in late 2019. All in all, the oil market appears to be far more balanced than it was in 2018 which presents a more favourable investment climate for our growth plans going forward.

In France, our team is focused on the execution of the Vert La Gravelle redevelopment project using horizontal drilling techniques and maturing the Villeperdue West project to a development decision later in the year.

As at end December 2018, IPC's 2P reserves have more than doubled to 288 MMboe (including 2P reserves attributable to the assets acquired in the BlackPearl Acquisition). This includes an excellent reserves replacement ratio of 103 percent excluding acquisition additions, following the maturation of contingent resources from the infill drilling program in Malaysia as well as better reservoir performance and certain upgrades in France and Canada, particularly on back of the gas optimization program in Canada.

In addition, we reported that our best estimate contingent resources as at end December 2018 have increased thirteen fold 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 development. 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 our value in the future.

Growth from Acquisition

In October 2018, IPC announced that it had agreed to the transformational acquisition of BlackPearl in an all share transaction. The transaction combines the highly free cash flow generative short cycle reserve base of IPC with the strategic long life reserve and contingent resource base of BlackPearl creating a company with the combined financial strength to accelerate value creation from the enlarged portfolio. IPC's 2P reserve base has more than doubled and the total reserve and contingent resource base has increased by more than six times to in excess of one billion barrels of oil equivalent. Reserves life is extended to more than sixteen years and production is expected to increase by around 50 percent in the short term. In addition a high calibre team of industry professionals with a long track record of value creation has joined IPC. BlackPearl's former CEO, John Festival, has joined the IPC Board to provide strategic direction. The transaction was approved by shareholders in both companies on December 7, 2018, and closed on December 14, 2018.

Netherlands Disposal

In December 2018, IPC completed the disposal of its gas business in the Netherlands characterized by a large number of small working interest, late life non-operated interests. A gain of USD 25 million was recognized on the disposal mainly driven by the release of decommissioning provisions.

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 2018, IPC recorded three low severity Lost Time Incident (LTI) in France, with no LTIs occurring in the fourth quarter.

Operations Overview

The acquisition of BlackPearl was completed on December 14, 2018, and the contribution from the acquired assets will be reported commencing from January 1, 2019.

Reserves and Resources

The IPC producing assets 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) is approximately 16 years. 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.

IPC remains focused on organic growth and is maturing opportunities across all our operated assets. In Canada, oil drilling activities commenced in the fourth quarter 2018, complemented by gas optimization activities that have halted the historical production decline. In Malaysia, we completed the second phase of infill drilling in the first quarter with two infill wells on stream and producing ahead of expectations. In France, IPC took an investment decision on the Vert La Gravelle development and work continues to mature Villeperdue West towards sanction and execution.

This focus on organic growth has led to a reserves replacement ratio of 103 percent for 2018, not including the 2P reserves acquired in the BlackPearl Acquisition. This was achieved organically by the teams in country through the extension of the infill drilling campaign in Malaysia, the gas optimization program in Canada and the work on the Villeperdue field in France.

Production

The average net production for the IPC assets during the fourth quarter of 2018 was above the high end of CMD guidance at 34.6 Mboepd. Integration of the Canadian assets has delivered a significant increase in production volumes for IPC relative to 2017 levels. In Malaysia, the addition of the two infill wells has increased production from the field relative to the equivalent period and the full year in 2017. The production during the reporting period with comparatives was comprised as follows:

Production in Mboepd	Three months ended December 31		12 months ended December 31	
	2018	2017	**2018**	2017
Crude oil				
Canada	6.3	–	6.3	–
Malaysia	6.8	6.5	7.3	6.7
France	2.4	2.4	2.5	2.4
Total crude oil production	**15.5**	8.9	**16.1**	9.1
Gas				
Canada	18.6	–	17.6	–
Netherlands	0.5	1.0	0.7	1.2
Total gas production	**19.1**	1.0	**18.3**	1.2
Total production	**34.6**	9.9	**34.4**	10.3
Quantity in MMboe	**3.18**	0.92	**12.56**	3.76

CANADA

Production in Mboepd	WI	Three months ended December 31 2018	Three months ended December 31 2017	12 months ended December 31 2018	12 months ended December 31 2017
- Crude Oil	100%	6.3	–	6.3	–
- Gas	99.7%[1]	18.6	–	17.6	–
Canada		**24.9**	–	**23.9**	–

[1] *On a well count basis.*

Production
Net production from the Canadian assets during the fourth quarter was above expectation at almost 25.0 Mboepd with continued excellent oil facility uptime performance. Gas production outperformed expectations due to the successful gas optimization campaign delivered throughout 2018. As at the end of the fourth quarter, over 7,800 wells have been swabbed compared to the original budget for the full year 2018 of 5,500, 64 out of the 106 planned well recompletions had been executed, with a further 200 planned siphon string / coil tubing optimizations realized.

Organic Growth and Capital Projects
A program of drilling and optimization activities was sanctioned by IPC as a part of the operational and capital budgets for 2018. New drilling in the oil pools in Canada commenced in the fourth quarter of 2018, which is the first drilling activity on the Suffield Assets in more than four years. Five horizontal wells had been drilled by the end of the fourth quarter, production was brought online post the reporting period in January 2019 and rates are in line with expectations. Regulatory approvals are in place to support continued drilling through the course of 2019, and the inventory of well locations beyond that is actively being screened and matured. Given the exceptional results from the 2018 gas optimization program further work is expected to continue through 2019.

BlackPearl Acquisition
The acquisition of BlackPearl was completed on December 14, 2018 and the financial and operational results for these assets will be reported commencing Q1 2019. The acquisition adds 160.1 MMboe of 2P reserves (as at December 31, 2018) and 784.3 MMboe of 2C best estimate contingent resource. The majority of the 2P reserves are attributable to Onion Lake Thermal with a smaller portion attributable to the Mooney EOR property. The majority of the 2C contingent resources are attributable to the Blackrod asset.

Onion Lake Thermal
A conventional heavy oil property located in the Lloydminster area in Saskatchewan, Onion Lake Thermal is a modified SAGD heavy oil project, producing oil of 10° to 11° API. The first 6,000 boepd phase of the project commenced production in 2015, with the second 6,000 boepd phase commencing steam injection during the first quarter of 2018. The second phase reached name-plate capacity of 12,000 boepd in the third quarter of 2018. During the second quarter of 2018, construction commenced on the first sustaining well pad and related facilities for the first phase. During the third quarter of 2018, work began on a facility optimization program of the first phase steam facilities. This optimization work is expected to allow an increase in thermal production by up to an additional 2,000 boepd (14,000 boepd for the full field) and be completed in the first half of 2019, taking approximately nine to twelve months after completion to reach the increased production target. Further work is ongoing to debottleneck the facilities and injection capability to increase the overall production, beyond the 14,000 boepd current capacity.

Blackrod
Blackrod is a 100% owned SAGD oil sands project located south of Fort McMurray, in the Athabasca oil sands region of northern Alberta. In 2016, regulatory and environmental approval was granted by the Alberta Energy Regulator and Alberta government for an 80,000 barrel per day SAGD development. A successful SAGD pilot program has run at Blackrod since 2011. The delineated resource contains 744 MMboe of best estimate contingent resource (unrisked). For the last six years, the SAGD pilot at Blackrod has been operated, which has validated both commercial production rates and a corresponding steam oil ratio. The oil quality at Blackrod ranges from 8° to 10° API. Two major sales oil and diluent pipeline systems are in close proximity to the Blackrod lands. IPC intends to continue work in 2019 to mature the development plans for this asset.

Conventional and EOR Properties
Mooney is a conventional heavy oil property located in northern Alberta. The field was initially developed using primary production techniques. In 2011, an alkali surfactant polymer flood (ASP flood) was initiated to enhance production and significantly increase overall oil recovery. The property has an average API of 16°.

Onion Lake Primary is a conventional heavy oil production property in Lloydminster Saskatchewan, with over 300 primary production wells with an average API gravity between 10° and 11°. Production from the Onion Lake area is currently exported via trucks to third party processing facilities, pipeline or rail terminals

Other Conventional - IPC holds interests and has ongoing operations and production in several other areas of Alberta and Saskatchewan including Reita Lake, Graindale, Portage, Fishing Lake, Salt Lake and Unity.

SOUTH EAST ASIA

Malaysia

Production in Mboepd	WI	Three months ended December 31 2018	2017	12 months ended December 31 2018	2017
Bertam	75%	**6.8**	6.5	**7.3**	6.7

Production
Net production from the Bertam field on Block PM307 during the fourth quarter of 2018 was ahead of expectation at 6.8 Mboepd. Strong reservoir performance was primarily attributed to production from the infill wells (A-15, A-16 and A-17), combined with high facility uptime during the fourth quarter of 2018 of above 99 percent.

Organic Growth
Following positive results from the 2016 and 2018 infill drilling programs and continued good reservoir performance, IPC is maturing the third phase of infill drilling on the Bertam field for execution in 2019. Up to three drilling locations have been identified for execution in 2019.

In addition, in the fourth quarter of 2018 Petronas approved the drilling of the Keruing prospect, allowing IPC to mature and develop the drilling plans for execution during 2019. The development solution in the Keruing success case is expected to be a tie-back to the Bertam FPSO utilizing the existing facilities, leading to a high value project.

CONTINENTAL EUROPE

Production in Mboepd	WI	Three months ended December 31 2018	2017	12 months ended December 31 2018	2017
France					
- Paris Basin	100% [1]	1.9	2.0	2.0	2.0
- Aquitaine	50%	0.5	0.4	0.5	0.4
Netherlands	Various	0.5	1.0	0.7	1.2
		2.9	3.4	**3.2**	3.6

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

France
Net production in France during the fourth quarter of 2018 was above expectation at 2.4 Mboepd.

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 Vert La Gravelle redevelopment project was approved for execution during the reporting period. Preparatory works commenced late in the fourth quarter of 2018, with an anticipated first well spud in the second quarter of 2019.

Processing and interpretation of the Villeperdue West 3D seismic data was completed in the fourth quarter of 2018 with the aim of reaching a final development investment decision in 2019. Furthermore we are evaluating the prospectively of the deeper Triassic horizon within the new 3D area which is produced by IPC in other parts of the Paris Basin.

The Netherlands

No production was reported for December 2018 due to the divestment of IPC Netherlands BV and IPC Netherlands Facilities BV effective on December 1, 2018. As a result of the sale, IPC no longer has any exploration or production assets in the Netherlands.

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 will be reported commencing from January 1, 2019.

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	2018	Q4 2018	Q3 2018	Q2 2018	Q1 2018	2017	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Revenue	**454,443**	**111,898**	106,746	120,637	115,162	203,001	54,647	47,926	48,496	51,932
Gross profit/(loss)	**146,864**	**26,311**	37,060	45,920	37,573	48,758	13,471	7,256	10,361	17,670
Net result	**103,644**	**29,346**	26,487	21,498	26,313	22,723	8,977	2,172	7,113	4,461
Earnings/(loss) per share – USD[1]	**1.13**	**0.29**	0.30	0.24	0.30	0.23	0.10	0.02	0.07	0.04
Earnings/(loss) per share fully diluted – USD[1]	**1.12**	**0.29**	0.29	0.23	0.30	0.23	0.10	0.02	0.07	0.04
Operating cash flow [2]	**279,018**	**58,322**	67,949	76,687	76,060	138,368	37,156	28,893	32,643	39,675
EBITDA [2]	**264,041**	**58,032**	66,240	74,478	65,291	129,259	33,383	26,440	30,049	39,387
Net debt at period end [2, 3]	**276,761**	**276,761**	213,217	254,628	309,184	26,321	26,321	47,241	35,348	(20,082)

[1] For comparative purposes, the Corporation's common shares issued under the Spin-Off, have been assumed to be outstanding as of the beginning of each period prior to the Spin-Off.

[2] See definition on page 21 under "Non-IFRS measures".

[3] Includes net debt of USD 111,156 thousand assumed from BlackPearl as at December 31, 2018.

Summarized consolidated balance sheet information is as follows:

USD Thousands	December 31, 2018	December 31, 2017
Non-current assets	1,184,184	455,235
Current assets	98,899	134,476
Total assets	**1,283,083**	589,711
Total non-current liabilities	490,981	219,097
Current liabilities	96,315	63,672
Total liabilities	**587,296**	282,769
Net assets	**695,787**	306,942
Working capital (including cash)	**2,584**	70,804

Segment Information

The Group operates within several geographical areas. Operating segments are reported at a country level which is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – December 31, 2018					
USD Thousands	**Canada**	**Malaysia**	**France**	**Netherlands**	**Other**	**Total**
Crude oil	13,970	48,643	20,258	11	–	**82,882**
NGLs	56	–	–	21	–	**77**
Gas	22,665	–	–	2,096	–	**24,761**
Net sales of oil and gas	**36,691**	**48,643**	**20,258**	**2,128**	**–**	**107,720**
Change in under/over lift position	–	–	22	–	–	**22**
Royalties	(559)	–	–	–	–	**(559)**
Other operating revenue	(2)	3,909	327	369	112	**4,715**
Revenue	**36,130**	**52,552**	**20,607**	**2,497**	**112**	**111,898**
Production costs	(27,604)	(12,717)	(11,791)	(700)	–	**(52,812)**
Depletion	(11,201)	(8,059)	(3,209)	(376)	–	**(22,845)**
Depreciation of other assets	–	(7,790)	–	–	–	**(7,790)**
Exploration and business development costs	–	(9)	(45)	–	(2,086)	**(2,140)**
Gross profit/(loss)	**(2,675)**	**23,977**	**5,562**	**1,421**	**(1,974)**	**26,311**

	Three months ended – December 31, 2017				
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Other**	**Total**
Crude oil	34,415	11,729	–	–	46,144
NGLs	–	–	54	–	54
Gas	–	–	3,714	–	3,714
Net sales of oil and gas	34,415	11,729	3,768	–	49,912
Change in under/over lift position	–	(23)	(108)	–	(131)
Other operating revenue	3,910	294	535	127	4,866
Revenue	38,325	12,000	4,195	127	54,647
Production costs	(7,849)	(7,369)	(2,156)	–	(17,374)
Depletion	(8,434)	(2,702)	(2,870)	–	(14,006)
Depreciation of other assets	(7,916)	–	–	–	(7,916)
Exploration and business development costs	352	(1,238)	–	(994)	(1,880)
Impairment costs	–	–	–	–	–
Gross profit/(loss)	14,478	691	(831)	(867)	13,471

USD Thousands	Year ended – December 31, 2018 Canada	Malaysia	France	Netherlands	Other	Total
Crude oil	106,661	181,722	69,596	66	–	**358,045**
NGLs	340	–	–	300	–	**640**
Gas	71,453	–	–	11,254	–	**82,707**
Net sales of oil and gas	**178,454**	**181,722**	**69,596**	**11,620**	**–**	**441,392**
Change in under/over lift position	–	–	408	11	–	**419**
Royalties	(6,296)	–	–	–	–	**(6,296)**
Other operating revenue	134	15,512	1,216	1,642	424	**18,928**
Revenue	**172,292**	**197,234**	**71,220**	**13,273**	**424**	**454,443**
Production costs	(113,003)	(26,959)	(34,120)	(5,776)	–	**(179,858)**
Depletion	(43,415)	(34,488)	(13,596)	(2,352)	–	**(93,851)**
Depreciation of other assets	–	(31,328)	–	–	–	**(31,328)**
Exploration and business development costs	–	(215)	(45)	–	(2,282)	**(2,542)**
Gross profit/(loss)	**15,874**	**104,244**	**23,459**	**5,145**	**(1,858)**	**146,864**

USD Thousands	Year ended – December 31, 2017 Malaysia	France	Netherlands	Other	Total
Crude oil	122,595	47,238	48	–	169,881
NGLs	–	–	338	–	338
Gas	–	–	14,963	–	14,963
Net sales of oil and gas	122,595	47,238	15,349	–	185,182
Change in under/over lift position	–	291	(178)	–	(613)
Other operating revenue	15,513	1,099	1,472	348	18,432
Revenue	138,108	48,403	16,142	348	203,001
Production costs	(30,393)	(26,118)	(7,926)	–	(64,437)
Depletion	(34,228)	(13,581)	(6,746)	–	(54,555)
Depreciation of other assets	(31,629)	–	–	–	(31,629)
Exploration and business development costs	346	(1,263)	–	(2,869)	(3,786)
Impairment costs	164	–	–	–	164
Gross profit/(loss)	42,368	7,441	1,470	(2,521)	48,758

Three months and year ended December 31, 2018 Review

Revenue
Total revenue amounted to USD 111,898 thousand for Q4 2018 compared to USD 54,647 thousand for Q4 2017 and USD 454,443 thousand for the year ended December 31, 2018, compared to USD 203,001 thousand for the year ended December 31, 2017, and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	**2018**	2017	**2018**	2017
Crude oil sales	82,882	46,144	358,045	169,881
Gas and NGL sales	24,838	3,768	83,347	15,301
Change in under/overlift position	22	(131)	419	(613)
Royalties	(559)	–	(6,296)	–
Other operating revenue	4,715	4,866	18,928	18,432
Total revenue	**111,898**	54,647	**454,443**	203,001

The components of total revenue for the three months and year ended December 31, 2018, and December 31, 2017, respectively are detailed below:

Crude oil sales

	Three months ended – December 31, 2018				
	Canada	**Malaysia**	**France**	**Netherlands**	**Total**
Crude oil sales					
- Revenue in USD thousands	13,970	48,643	20,257	12	**82,882**
- Quantity sold in bbls	655,906	665,466	305,579	154	**1,627,105**
- Average price realized USD per bbl	21.30	73.10	66.29	80.05	**50.94**

	Three months ended – December 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	34,415	11,729	–	46,144
- Quantity sold in bbls	524,723	185,098	–	709,821
- Average price realized USD per bbl	65.59	63.37	–	65.01

Crude oil revenue was 80 percent higher for Q4 2018 compared to Q4 2017 mainly due to the contribution of Suffield Assets in Canada from January 5, 2018, increased cargo sizes in Malaysia, a cargo lifting in Aquitaine Basin, France and an increase in the underlying oil price.

The 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 Q4 2018, WTI averaged USD 59 per bbl and the average discount to WCS used in our pricing formula was USD 39 per bbl. The discount to WCS used in our November and December pricing formulas widened to USD 46 per bbl and USD 43 per bbl respectively, before significantly narrowing for January and February pricing to around USD 17 per bbl and USD 10 per bbl respectively following production curtailment announcements by the Alberta government at the beginning of December 2018.

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 69 per bbl for Q4 2018 compared to USD 61 per bbl for the comparative period.

	Year ended – December 31, 2018				
	Canada	**Malaysia**	**France**	**Netherlands**	**Total**
Crude oil sales					
- Revenue in USD thousands	106,661	181,721	69,596	67	**358,045**
- Quantity sold in bbls	2,655,404	2,426,797	991,057	1,063	**6,074,321**
- Average price realized USD per bbl	40.17	74.88	70.22	63.50	**58.94**

	Year ended – December 31, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	122,595	47,238	48	169,881
- Quantity sold in bbls	2,139,683	890,527	1,097	3,031,307
- Average price realized USD per bbl	57.30	53.05	43.57	56.04

Crude oil sales were 110 percent higher for the year ended December 31, 2018, compared to the year ended December 31, 2017, due mainly to the contribution of Suffield Assets in Canada from January 5, 2018, and an increase in the underlying oil price.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. WTI averaged USD 65 per bbl and the average discount to WCS used in our pricing formula was USD 26 per bbl for the year ended December 31, 2018.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 71 per bbl year ended December 31, 2018 compared to USD 54 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – December 31, 2018		
	Canada	**Netherlands**	**Total**
Gas and NGL sales			
- Revenue in USD thousands	22,721	2,117	**24,838**
- Quantity sold in Mcf	9,707,890	255,500	**9,963,390**
- Average price realized USD per Mcf	2.34	8.29	**2.49**

	Three months ended – December 31, 2017	
	Netherlands	**Total**
Gas and NGL sales		
- Revenue in USD thousands	3,768	3,768
- Quantity in Mcf	598,044	598,044
- Average price realized USD per Mcf	6.30	6.30

Gas and NGL sales revenue was 560 percent higher for Q4 2018 compared to Q4 2017 mainly due to the contribution of the Suffield Assets from January 5, 2018. Canadian gas and NGL sales revenue represented approximately 91 percent of the total revenue from gas and NGL sales for Q4 2018. Over 98 percent 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 Q4 2018, IPC realized an average price of CAD 3.07 per Mcf which was CAD 1.51 per Mcf, or approximately 97 percent, above AECO pricing.

Dutch gas volumes sold in Q4 2018 are lower than the comparative period due to the naturally declining production as well as no contribution in December 2018 following the sale of the Dutch assets on December 1, 2018.

	Year ended – December 31, 2018		
	Canada	Netherlands	Total
Gas and NGL sales			
- Revenue in USD thousands	71,793	11,554	**83,347**
- Quantity sold in Mcf	36,439,974	1,551,527	**37,991,501**
- Average price realized USD per Mcf	1.97	7.45	**2.19**

	Year ended – December 31, 2017	
	Netherlands	Total
Gas and NGL sales		
- Revenue in USD thousands	15,301	15,301
- Quantity in Mcf	2,722,099	2,722,099
- Average price realized USD per Mcf	5.62	5.62

Gas and NGL sales revenue was 445 percent higher for the year ended December 31, 2018, compared to the year ended December 31, 2017, mainly due to the due to the contribution of Suffield Assets in Canada from January 5, 2018 . For the year ended 2018 IPC realized an average price of CAD 2.54 per Mcf which was CAD 1.04 per Mcf, or approximately 70 percent, above AECO pricing.

Other operating revenue

Other operating revenue amounted to USD 4,715 thousand for Q4 2018 compared to USD 4,866 thousand for Q4 2017 and USD 18,928 thousand for the year ended December 31, 2018, compared to USD 18,432 thousand for the year ended December 31, 2017. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia.

Production costs

Production costs including inventory movements amounted to USD 52,812 thousand for Q4 2018 compared to USD 17,374 thousand for Q4 2017 and USD 179,858 thousand for the year ended December 31, 2018, compared to USD 64,437 thousand for year ended December 31, 2017, and is analyzed as follows:

	Three months ended – December 31, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	23,314	21,643	7,737	700	(11,730)	**41,664**
USD/boe[2]	10.17	34.75	34.47	16.38	n/a	**13.09**
Cost of blending[4]	4,678	–	–	–	–	**4,678**
Change in inventory position	(388)	2,804	4,054	–	–	**6,470**
Production costs	**27,604**	**24,447**	**11,791**	**700**	**(11,730)**	**52,812**

	Three months ended – December 31, 2017				
USD Thousands	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	19,032	8,810	2,156	(11,729)	18,269
USD/boe[2]	31.66	40.29	22.54	n/a	19.95
Change in inventory position	546	(1,441)	–	–	(895)
Production costs	19,578	7,369	2,156	(11,729)	17,374

	Year ended – December 31, 2018					
USD Thousands	Canada	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	90,068	75,966	30,084	5,776	(46,538)	**155,356**
USD/boe[2]	10.32	28.50	33.26	22.22	n/a	**12.37**
Cost of blending[4]	24,512	–	–	–	–	**24,512**
Change in inventory position	(1,577)	(2,469)	4,036	–	–	**(10)**
Production costs	**113,003**	**73,497**	**34,120**	**5,776**	**(46,538)**	**179,858**

	Year ended – December 31, 2017				
USD Thousands	Malaysia	France	Netherlands	Other [3]	Total
Operating costs[1]	73,540	25,820	7,926	(46,537)	60,749
USD/boe[2]	30.14	29.00	18.35	n/a	16.15
Change in inventory position	3,390	298	–	–	3,688
Production costs	76,930	26,118	7,926	(46,537)	64,437

[1] *See definition on page 21 under "Non-IFRS measures"*

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

[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating cost per boe for Malaysia to USD 15.92 and USD 12.15 for Q4 2018 and Q4 2017 respectively and USD 11.04 and USD 11.07 for the year ended December 31, 2018, and December 31, 2017, respectively.*

[4] *Cost of blending represents the contracted purchase of diluent used for blending net of proceeds from the sale of surplus diluent. For the year ended December 31, 2018, a cost of USD 684 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent.*

Operating costs

Operating costs amounted to USD 41,664 thousand for Q4 2018 compared to USD 18,269 thousand for Q4 2017 and USD 155,356 thousand for the year ended December 31, 2018, compared to USD 60,749 thousand for the year ended December 31, 2017. The increase in operating costs is mainly due to the contribution of Suffield Assets in Canada from January 5, 2018 and the total operating costs per boe for the year ended December 31, 2018, is USD 12.37 per boe and is below CMD guidance of USD 12.60 per boe. The operating costs in France for the year ended December 31, 2018, increased compared to the year ended December 31, 2017, as a result of the increased production taxes due to tax legislation changes announced in Q4 2017.

Operating costs per boe amounted to USD 13.09 in Q4 2018 compared to USD 19.95 in Q4 2017 with Canada for Q4 2018 costing USD 10.17 per boe. In Malaysia, there was a workover of a well in Q4 2018 for a total cost USD 2,275 thousand.

Cost of blending

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 4,678 thousand for Q4 2018 and to USD 24,512 thousand for the year ended December 31, 2018. As a result of the blending, actual sales volumes are higher than produced barrels. For the year ended December 31, 2018, a cost of USD 684 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent.

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. In the Aquitaine Basin, France, there was a cargo lifting in both Q1 and Q4 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 22,845 thousand for Q4 2018 compared to USD 14,006 thousand for Q4 2017 and USD 93,851 thousand for the year ended December 31, 2018, compared to USD 54,555 thousand for the year ended December 31, 2017, with the inclusion of a USD 11,201 thousand depletion charge for Q4 2018 and USD 43,415 thousand for the year ended December 31, 2018, relating to the Suffield Assets. The depletion charge per country is analyzed in the following tables:

	Three months ended – December 31, 2018				
	Canada	Malaysia	France	Netherlands	Total
Depletion cost in USD thousands	11,201	8,059	3,209	376	**22,845**
USD per boe	4.89	12.94	14.30	8.79	**7.18**

	Three months ended – December 31, 2017			
	Malaysia	France	Netherlands	Total
Depletion cost in USD thousands	8,434	2,585	2,870	13,889
USD per boe	14.03	11.83	29.97	15.17

	Year ended – December 31, 2018				
	Canada	Malaysia	France	Netherlands	Total
Depletion cost in USD thousands	43,415	34,488	13,596	2,352	**93,851**
USD per boe	4.97	12.94	15.03	9.05	**7.47**

	Year ended – December 31, 2017			
	Malaysia	France	Netherlands	Total
Depletion cost in USD thousands	34,228	13,464	6,746	54,438
USD per boe	14.03	15.12	15.62	14.47

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field. Following the allocation of the purchase price for the Suffield Assets, the depletion rate for Canada for 2018 is calculated at CAD 6.44 per boe (USD 4.97 per boe).

Depreciation of other assets

The total depreciation of other assets amounted to USD 31,328 thousand for the year ended December 31, 2018, compared to USD 31,629 thousand for the year ended December 31, 2017. This related to the depreciation of the FPSO Bertam, which is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 11,065 thousand for the year ended December 31, 2018, compared to USD 10,400 thousand for the year ended December 31, 2017. Until the Spin-Off date in April 2017, the general administrative and depreciation expenses are a carve out from Lundin Petroleum's financial statements and are not representative of the general, administrative and depreciation expenses associated with the Group's corporate structure post Spin-Off.

Net financial items

Net financial items amounted to USD 46,930 thousand for the year ended December 31, 2018, compared to USD 14,907 thousand for the year ended December 31, 2017. Included in the year ended December 31, 2018, is interest expense of USD 14,732 thousand on the external loan facilities which were drawn to fund the Suffield acquisition at the beginning of January 2018 compared to USD 1,378 for the comparative period and the unwinding of the discount rate on the asset retirement obligations which amounted to a non-cash charge of USD 9,190 thousand for 2018 compared to USD 3,557 thousand for 2017. The increase in the unwinding of the discounting rate is largely due to the Suffield Assets retirement obligation included from January 5, 2018. Also for the year end December 31, 2018, there is a largely non-cash net foreign exchange loss of USD 17,354 thousand compared to a net foreign exchange loss of USD 8,922 thousand in 2017 mainly resulting from the revaluation of external loan balances and intra-group loan funding balances.

Income tax

The corporate income tax charge amounted to USD 10,265 thousand for the year ended December 31, 2018, compared to USD 728 thousand for the year ended December 31, 2017. There was a current tax credit of USD 7,196 thousand in 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 year ended December 31, 2018, was as follows:

USD Thousands	Canada	Malaysia	France	Netherlands	Total
Development	15,040	12,928	6,129	1,182	**35,279**
Exploration and evaluation	–	2,805	759	201	**3,765**
	15,040	15,733	6,888	1,383	**39,044**

Capital expenditure for the year ended December 31, 2018, is below the full year guidance given at Q3 2018 of USD 44 million due mainly to the phasing of the Keruing prospect drilling in Malaysia into 2019. The 2018 development expenditure in Malaysia mainly relates to the drilling of the second infill well on the Bertam field in Q1 2018. The two well drilling campaign started in December 2017 and was completed under budget in Q1 2018. In Canada, drilling in the Suffield Assets oil pools commenced in the fourth quarter of 2018 and five horizontal wells were drilled by year end.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 92,149 thousand as at December 31, 2018, which included USD 88,706 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Acquisition of the Suffield Assets

On January 5, 2018, IPC acquired the Suffield Assets from Cenovus Energy Inc. for a total consideration, after preliminary closing adjustments and an assessment of the contingent consideration, of USD 376,967 thousand. The purchase price has been allocated, on a preliminary basis, as follows:

USD Thousands	
Property, Plant and Equipment, net	454,735
Deferred tax liabilities	(2,682)
Abandonment retirement obligation	(75,086)
Net assets acquired	**376,967**

There was no goodwill or negative goodwill recorded on the acquisition.

The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed, as well as to the fair value of the consideration transferred.

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 recognised 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	72,925
Property, plant and equipment	358,301
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)
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 are expected to be recognized in 2019.

The amounts disclosed above were determined provisionally pending the finalization of the valuation for those assets and liabilities. Up to twelve months from the effective date of the BlackPearl Acquisition, further adjustments may be made to the fair values assigned to the identifiable assets acquired and liabilities assumed

Disposal of Netherlands Assets

On December 1, 2018, IPC completed the sale of its non-core, non-operated gas assets in the Netherlands with an effective date of January 1, 2018, and recognized an accounting profit of USD 25,040 thousand.

USD Thousands	
Release of asset retirement obligation	42,449
Disposal of exploration and evaluation assets	(1,083)
Disposal of Property, plant and equipment	(14,080)
Other[1]	(2,246)
Gain on sale	**25,040**

[1]*Including repayment of the net revenue from the effective date.*

Financial Position and Liquidity

Financing

In connection with the April 2017 spin-off of IPC, the Group entered into a USD 100 million reserve-based lending credit facility, which was used to fund the offer to purchase common shares of IPC. The credit facility was initially drawn for USD 80.0 million in May 2017.

In connection with the completion of the Suffield acquisition, the Group entered into an amendment to the reserve-based lending credit facility in December 2017 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 on January 5, 2018.

On January 5, 2018, following completion of the Suffield acquisition, the Group had net debt of approximately USD 355 million which was mainly used to pay the Suffield acquisition price of CAD 449 million (net of closing adjustments and including a CAD 40 million deposit).

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 acquisition of BlackPearl, the Group assumed the debt of BlackPearl consisting of a reserve-based lending credit facility of CAD 120 million (CAD 80 million outstanding as at December 31, 2018) and senior secured notes outstanding of CAD 75 million. The reserve-based lending facility matures in May 2021 and the senior secured notes mature in June 2020.

The borrowing base availability under the Group's reserve-based lending credit facility is currently USD 166 million of which USD 68 million was outstanding as at December 31, 2018. The borrowing base availability of IPC Alberta Ltd.'s reserve-based lending credit facility is currently CAD 200 million of which CAD 144 million was outstanding as at December 31, 2018, with a maturity date of January 2021.

Total net debt as at December 31, 2018, amounted to USD 276.8 million which included USD 111.2 million of assumed net debt from the BlackPearl acquisition.

The Group's free cash flows going forward, after operations related costs and capital expenditure, are planned to continue to be used to repay outstanding debt under the 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 10,626 thousand as at December 31, 2018. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

In connection with the Spin-Off, effective January 1, 2017, IPC owed working capital in favor of Lundin Petroleum. USD 33.5 million of the working capital adjustment including interest was paid back to Lundin Petroleum in 2017 and a further amount of USD 10 million was paid in December 2018. The final settlement of USD 14.0 million plus interest is due before June 30, 2019.

Working Capital

As at December 31, 2018, the Group had a net working capital balance including cash of USD 2,584 thousand compared to USD 70,804 thousand as at December 31, 2017. The main movement in working capital during the year ended December 31, 2018, was the allocation of the deposit in relation to the Suffield acquisition of USD 31,898 thousand to the purchase price for the Suffield Assets and the impact of the acquisition of the Suffield assets and of BlackPearl. The amounts are derived from the balance sheet and the change in working capital differs to the amount stated in the statement of cash flow due to the inclusion of the cash balances and the non-cash foreign exchange differences arising on the revaluation of the balances held in subsidiaries with a different functional currency to the Group's presentational currency.

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 consolidated financial statements:

	Three months ended December 31		Year ended December 31	
USD Thousands	**2018**	2017	**2018**	2017
Revenue	111,898	54,647	454,443	203,001
Production costs	(52,812)	(17,374)	(179,858)	(64,437)
Current tax	(764)	(117)	4,433	(196)
Operating cash flow	**58,322**	37,156	**279,018**	138,368

EBITDA

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

	Three months ended December 31		Year ended December 31	
USD Thousands	**2018**	2017	**2018**	2017
Net result	29,346	8,977	103,644	22,723
Net financial items	19,438	2,191	46,930	14,907
Income tax	1,414	(1,772)	10,265	728
Depletion	22,845	14,006	93,851	54,555
Depreciation of other assets	7,790	7,916	31,328	31,629
Exploration and business development costs	2,140	1,880	2,542	3,786
Impairment costs	–	–	–	(164)
Sale of assets	(25,040)	–	(25,040)	–
Depreciation included in general, administration and depreciation expenses [1]	99	185	521	1,095
EBITDA	**58,032**	33,383	**264,041**	129,259

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

Operating costs

The following table sets out how operating costs is calculated:

	Three months ended December 31		Year ended December 31	
USD Thousands	**2018**	2017	**2018**	2017
Production costs	52,812	17,374	179,858	64,437
Cost of blending[1]	(4,678)	–	(24,512)	–
Change in inventory position	(6,470)	895	10	(3,688)
Operating costs	**41,664**	18,269	**155,356**	60,749

[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 consolidated financial statements:

USD Thousands	December 31, 2018	December 31, 2017
Bank loans	232,357	60,000
Senior secured notes	55,030	–
Cash and cash equivalents	(10,626)	(33,679)
Net debt	**276,761**	26,321

Off-Balance Sheet Arrangements

On May 1, 2018, IPC, through its subsidiary IPC Alberta Ltd, had issued a letter of credit for an amount of CAD 4 million in respect of its obligations to purchase diluent. The letter of credit automatically renewed on July 31, 2018, and every six months thereafter unless notice is given to terminate the letter of credit.

IPC has also guaranteed the pipeline obligations of its subsidiary, IPC Alberta 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 started trading on both the Toronto Stock Exchange and the Nasdaq First North in Stockholm on April 24, 2017, with a total of 113,462,148 common shares issued and outstanding. As part of the share purchase offer by a subsidiary of IPC announced following listing, 25,540,302 common shares were tendered (including the 22,805,892 common shares owned by Statoil) and, as part of a subsequent internal reorganization, these shares were subsequently cancelled. Following the completion of the share purchase offer, the total number of common shares issued and outstanding in IPC was 87,921,846. In June 2018, IPC's shares ceased trading on the Nasdaq First North and commenced trading on the Nasdaq Stockholm.

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 February 12, 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 37,903,757 common shares in IPC.

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 1,818,100 stock options, 791,753 IPC transitional PSP and RSP awards granted in connection with the Spin-off and 708,272 IPC Performance and Restricted Share Plan awards granted in July 2018, outstanding as at February 12, 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. The potential undiscounted amount of all future payments that the Group could be required to pay as at December 31, 2018 is up to CAD 18 million. An estimated contingent consideration of CAD 10,371 thousand (USD 8,354 thousand) as at December 31, 2018, has been reflected in the Financial Statements. Of this amount, the Group has paid, or will pay, a total amount of CAD 3,868 thousand for oil and CAD 2,003 thousand for gas as contingent consideration related to the oil and gas price for the year 2018.

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 21 Provisions of the Financial Statements.

The Bertam field (IPC working interest of 75 percent) has leased the FPSO Bertam from another Group company for an initial period of six years commencing April 2015.

IPC has a residual liability for working capital owed to Lundin Petroleum – see Transactions with Related Parties section below.

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 of USD 14,008 thousand including accrued interest as at December 31, 2018 following a further USD 10,000 thousand payment in December 2018. Instalments relating to the working capital amount bear interest at 3.5% from the date of the original repayment schedule. The amount is reflected as a current liability as it is due before the end of June 2019. Expensed interest of USD 548 thousand is included in 2018 related to this liability.

Lundin Petroleum has charged the Group USD 678 thousand in respect of office space rental and USD 2,348 thousand in respect of shared services provided during the year 2018. IPC has charged Lundin Petroleum USD 146 thousand in respect of consultancy fees during the year 2018.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2018, 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. IPC is required to hedge a certain portion of the oil production from the assets acquired in the BlackPearl Acquistion, under the terms of the CAD 75 million senior secured notes.

The Group had entered into the following forward gas price hedges as at December 31, 2018, as follows:

Period	Volume (Gigajoules (GJ) per day)	Average Pricing
Gas Sale		
January 1, 2019 - March 31, 2019	25,000	AECO 5a + CAD 0.89/GJ
January 1, 2019 - March 31, 2019	25,000	Fixed Price @ CAD 4.27/GJ
January 1, 2019 - March 31, 2019	2,500	AECO 5a + CAD 2.655/GJ
January 1, 2019 - March 31, 2019	5,500	AECO 5a + CAD 3.055/GJ
January 1, 2019 - March 31, 2019	2,000	AECO 5a + CAD 2.985/GJ
January 1, 2019 - March 31, 2019	2,500	AECO 5a + CAD 3.355/GJ
January 1, 2019 - March 31, 2019	2,500	Sell 5a Floating / Buy CAD 1.41/GJ Fixed
January 1, 2019 - March 31, 2019	2,500	Fixed Price @ CAD 4.35/GJ
January 1, 2019 - March 31, 2019	2,500	Fixed Price @ CAD 4.365/GJ
January 1, 2019 - January 31, 2019	7,500	Fixed Price @ CAD 4.06/GJ
January 1, 2019 - January 31, 2019	2,500	AECO 5a + CAD 2.355/GJ
January 1, 2019 - March 31, 2019	2,500	Gas Daily Iroquois – USD 1.95/MMBTU
Gas Purchase		
January 1, 2019 - December 31, 2019	2,000	AECO 5a + CAD 1.50/GJ
January 1, 2019 - December 31, 2019	4,000	AECO 5a + CAD 1.65/GJ
January 1, 2019 - December 31, 2019	2,000	AECO 5a + CAD 1.53/GJ
January 1, 2020 - December 31, 2020	2,000	AECO 5a + CAD 1.4875/GJ
January 1, 2019 - December 31, 2020	2,000	AECO 5a + CAD 1.4950/GJ

The Group had entered into the following forward oil price hedges as at December 31, 2018, as follows:

Period	Volume (barrels per day)	Average Pricing
January 1, 2019 - March 31, 2019	500	WTI USD 40/bbl to USD 60/bbl
January 1, 2019 - March 31, 2019	500	WTI USD 43.25/bbl to USD 57/bbl
January 1, 2019 - March 31, 2019	1,600	WTI USD 40/bbl to USD 58.25/bbl
January 1, 2019 - March 31, 2019	2,000	WTI USD 50/bbl to USD 62.75/bbl
January 1, 2019 - March 31, 2019	2,000	WTI USD 50/bbl to USD 65.95/bbl
January 1, 2019 - March 31, 2019	1,000	WTI USD 35/bbl to USD 55.15/bbl
April 1, 2019 – June 30, 2019	1,500	WTI USD 45/bbl to USD 59.05/bbl
April 1, 2019 – June 30, 2019	1,200	WTI USD 45/bbl to USD 59.75/bbl
April 1, 2019 – June 30, 2019	1,000	WTI USD 50/bbl to USD 72.05/bbl
April 1, 2019 – June 30, 2019	1,000	WTI CAD 65/bbl to CAD 93/bbl
April 1, 2019 – June 30, 2019	1,000	WCS CAD 53/bbl
April 1, 2019 – June 30, 2019	1,000	WCS CAD 55/bbl
April 1, 2019 – June 30, 2019	500	WTI USD 50/bbl to USD 82.90/bbl
July 1, 2019 – September 30, 2019	2,000	WTI USD 50/bbl to USD 59.25/bbl
July 1, 2019 – September 30, 2019	2,000	WTI USD 50/bbl to USD 62/bbl
July 1, 2019 – September 30, 2019	4,000	WTI USD 50/bbl to USD 81.30/bbl
July 1, 2019 – September 30, 2019	500	WTI USD 50/bbl to USD 81.75/bbl
October 1, 2019 – December 31, 2019	1,500	WTI USD 50/bbl to USD 69.35/bbl
October 1, 2019 – December 31, 2019	1,500	WTI CAD 65/bbl to CAD 89.00/bbl
January 1, 2020 - March 31, 2020	3,500	WTI USD 50/bbl to USD 77.50/bbl
April 1, 2020 – June 30, 2020	2,750	WTI USD 35/bbl to USD 63.50/bbl

These hedges had a fair value net asset of USD 12,751 thousand at December 31, 2018.

Currency Risk

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

Interest Rate Risk

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

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

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

RISK AND UNCERTAINTIES

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

Non Financial Risks

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

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

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

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

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

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

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

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

Operational Risks: The pipelines and facilities associated with the Group's assets, including the FPSO Bertam, are exposed to operational risks that can lead to hydrocarbon releases and unplanned outages. Other operating risks relating to the facilities and pipelines associated with the Group's assets include: the breakdown or failure of equipment; issues and failures affecting the FPSO Bertam; breakdown or malicious attacks on information systems or processes; the performance of equipment at levels below those originally intended; operator error; disputes and other issues with interconnected facilities; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs and other similar events, many of which will be beyond the control of the Group. The occurrence or continuance of any of these or other operational events could curtail sales or production or materially increase the cost of operating the facilities and pipelines associated with the Group's oil and gas assets and reduce revenues accordingly.

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

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

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

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves". This MD&A contains estimates of the net present value of the future net revenue from IPC's reserves. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material. See also "Reserves and Resource Data" below.

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

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

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

The French government has enacted legislation to cease granting new petroleum exploration licenses in France and to restrict the production of oil and gas under existing production licenses in France from 2040. The Group continues to work closely with other industry participants and the French authorities with respect to this legislation. IPC does not expect that this legislation will have a material adverse effect on the Group's operations or financial condition.

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

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

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

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

Reliance on Third-Party Operators: The Group has partners in many of the licence, lease and PSC areas associated with the Group's assets. In some cases, including in the Aquitaine Basin in France, the Group is not the operator of the licence and concession areas and must depend on the competence, expertise, judgment and financial resources (in addition to those of its own and, where relevant, other partnership and joint venture companies) of the partner operator and the operator's compliance with the terms of the licences, leases, PSCs and contractual arrangements. Mismanagement of licence areas by the Group's partner operators or defaults by them in meeting required obligations may result in significant exploration, production or development delays, losses or increased costs to the Group.

Reliance on Third-Party Infrastructure: The Group delivers the products associated with the Group's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Group is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Group's business financial condition, results of operations, cash flows and future prospects.

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

In addition, the maximum amount that the Group is permitted to borrow under its senior credit facilities is subject to periodic review by the lenders. The Group's lenders generally review its oil and gas production and reserves, forecast oil and gas prices, general business environment and other factors to establish the amount which the Group is entitled to borrow. In the event the lenders decide to reduce the amount of credit available under the senior credit facilities, the Group may be required to repay all or a portion of the amounts owing thereunder.

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

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

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

Climate Change Legislation: The oil and natural gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. Furthermore, management of the Corporation believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is a risk that any such programs, laws or regulations, if proposed and enacted, will contain emission reduction targets which the Corporation cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets.

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

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

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

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

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

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

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

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

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

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

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

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

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

Significant Shareholders: 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 (the "Trust Entities"), own approximately 23 percent of the aggregate voting shares of the Corporation. The Trust Entities' holdings may allow them to significantly affect substantially all the actions taken by the shareholders of the Corporation, including the election of directors. As long as the Trust Entities maintain a significant interest in the Corporation, it is likely that the Trust Entities will exercise significant influence on the ability of the Corporation to, among other things, amend the articles of the Corporation, enter into a change in control transaction of the Corporation that might otherwise be beneficial to its shareholders and may also discourage acquisition bids for the Corporation. There is a risk that the interests of the Trust Entities will not be aligned with the interests of other shareholders.

Financial Risks

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

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

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

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

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

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

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

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

Financial markets can experience significant price and volume fluctuations that may particularly affect the market prices of equity securities of companies and that may be unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Corporation's operating results, underlying asset values or prospects have not changed. These factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2018, 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 the Suffield Assets

The acquisition of the Suffield Assets in southern Alberta, Canada 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 operating effectiveness of disclosure controls and procedures and internal controls over financial reporting in respect of these assets.

Acquisition of BlackPearl

The acquisition of BlackPearl 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 in the Note 11 of the Financial Statements.

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;
- IPC's 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 proposed Vert La Gravelle development project and other organic growth opportunities in France, including the Villeperdue West project;
- the proposed third phase of infill drilling in Malaysia and the ability to mature additional locations;
- the drilling of the Keruing prospect in Malaysia and the development options if drilling is successful;
- future development potential of the Suffield operations, including continued and future oil drilling and gas optimization programs;
- the state of the oil markets, including in Canada following the curtailments announced by the Alberta government in 2018;
- future development of the Blackrod project in Canada;
- the results of the facility optimization program and the work to debottleneck the facilities and injection capability at Onion Lake Thermal;
- the ability to integrate the assets and operations acquired in the BlackPearl Acquisition, including the ability to accelerate value creation and extend IPC's reserves life following such acquisition;
- 2019 production range, exit rate, operating costs and capital expenditure;
- potential further acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- estimates of prospective resources;
- the ability to generate free 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.

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 Corporation's material change report dated February 12, 2019 (MCR), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2017 (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 DATA

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 the report 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 MCR.

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 acquisition of BlackPearl which completed on December 14, 2018).

Light and medium 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 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Each of the reserves categories (proved, probable and possible) 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, possible) 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 percent 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

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
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 light 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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