Q3

International Petroleum Corporation

Management's Discussion and Analysis

Three and nine months ended September 30, 2017

International Petroleum Corp.

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UNAUDITED

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 which are not generally accepted accounting measures under IFRS and therefore may not be comparable with definitions of OCF, EBITDA, operating costs and Net Debt that may be used by other entities. Management believes that OCF, EBITDA, operating costs and Net Debt are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 20.

Forward-Looking Statements
Certain statements contained in this MD&A constitute forward-looking information under applicable Canadian securities laws. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "forecast", "estimate", "expect", "seek", "anticipate", "plan", "continue", "project", "predict", "intend", "objectives", "strategies", "potential", "target", "guidance", "may", "will", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. International Petroleum Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. For additional information underlying forward-looking information, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 28.

Unless otherwise stated, reserve estimates and estimates of future net revenue are effective as of 31 December 2016 and were prepared by IPC in accordance with standards prescribed by National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators (NI 51-101) and audited by ERC Equipoise Ltd., an independent qualified reserves auditor.

Unless otherwise stated, the estimates of best estimate contingent resources contained in this MD&A are based on an evaluation of contingent resources that was prepared by a qualified reserves evaluator, as defined in NI 51-101. The reserves evaluator is not independent of IPC for the purposes of NI 51-101.

Reserves estimates and contingent resource estimates in respect of the Suffield/Alderson assets are based on the evaluation of these assets as at September 1, 2017 prepared by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserve evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's July 1, 2017 price forecasts. The volumes are reported from an economic reference date of December 31, 2017.

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

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INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated November 7, 2017 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2017 ("Financial Statements").

Formation of IPC

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

IPC acquired the Malaysian, French and Dutch assets through a series of reorganization transactions (the "Reorganization") which are summarized in a non-offering long form prospectus of IPC dated April 17, 2017 (the "Final Prospectus"), filed with the Alberta Securities Commission on the same date. The Reorganization was completed on April 7, 2017.

Prior to opening of trading on Toronto Stock Exchange and Nasdaq First North, Lundin Petroleum distributed all of the IPC Common Shares on a pro-rata basis to Lundin Petroleum AB shareholders and such holders of Lundin Petroleum shares received one Common Share for every three shares of Lundin Petroleum AB. The distribution and first day of trading of IPC's shares on the Toronto Stock Exchange and Nasdaq First North occurred on April 24, 2017.

Further information in respect of IPC, the Reorganization and the Spin-Off are available in the Final Prospectus. A copy of the Final Prospectus may be obtained on SEDAR at www.sedar.com under the profile 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 Malaysia, France and the Netherlands with exposure to growth opportunities. IPC also acquired certain legacy non-producing interests and non-active entities as part of the Spin-Off, which are in the process of being relinquished and liquidated.

Basis of Preparation

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

Financial information is presented in United States Dollars ("USD" or "US$"). However, as the Group operates in Europe, certain financial information prepared by subsidiaries has been reported in Euros ("EUR"). In addition, certain costs relating to the operations in Malaysia, which are reported in USD, are incurred in Malaysian Ringgit ("MYR"). Exchange rates for the relevant currencies of the Group with respect to the US Dollar are as follows:

	September 30, 2017		September 30, 2016		December 31, 2016	
	Average	Period end	Average	Period end	Average	Period end
1 EUR equals USD	1.1132	1.1806	1.1158	1.1161	1.1066	1.0541
1 USD equals MYR	4.3469	4.2205	4.0859	4.1348	4.1455	4.4860

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THIRD QUARTER 2017 HIGHLIGHTS

Business Development

Suffield Acquisition

- Agreement signed to purchase the conventional oil and natural gas assets in the Suffield and Alderson areas of Southern Alberta, Canada from Cenovus Energy Inc. for CAD 512 million, subject to closing adjustments and certain additional contingent consideration.
- The acquisition is expected to be fully funded through debt financing and is expected to close by the end of the year.

Operational Highlights

Production and Operating Costs

- Total average production of 9,200 barrels of oil equivalent (boe) per day (boepd) net for the third quarter of 2017 and 10,400 boepd for the first nine months of 2017 (the "reporting period"), 7 percent and 4 percent ahead of mid-point guidance respectively.
- Revised production guidance of 10,000 to 10,500 boepd from 9,000 to 11,000 boepd.
- Operating costs[1] per boe below guidance at USD 18.71 for the third quarter of 2017 (February 2017 Capital Markets Day (CMD) - USD 22.0) and USD 14.92 for the reporting period (CMD – USD 18.75). The third quarter result included the impact of higher one off costs and lower production as a result of the planned Bertam shutdown.
- Operating cost guidance for the full year is reduced to USD 16.20 per boe from Q2 guidance of USD 17.20 per boe.

Projects and Capital Activities

- Best estimate contingent resources assessed by IPC at 17.5 million boe (MMboe) as at June 30, 2017.
- Capital expenditure guidance for 2017 reduced to USD 33 million (Q2 guidance USD 38 million).
- 3D seismic acquisition in the Villeperdue field (France – Paris Basin) was completed in October 2017.
- Partner approval and rig contract secured for two infill wells in Malaysia. Drilling expected to commence during the fourth quarter.

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

Financial Highlights

US$ Thousands	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Revenue	**47,926**	48,498	**148,354**	150,288
Gross profit/(loss)	**7,256**	9,631	**35,287**	8,961
Net result	**2,172**	4,522	**13,746**	(19,623)
Operating cash flow [1]	**28,893**	38,911	**101,212**	110,841
EBITDA [1]	**26,440**	38,439	**95,876**	108,917
Net debt [1]	**47,241**	(8,443)	**47,241**	(8,443)

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

- Senior secured revolving borrowing base facility entered into on April 20, 2017 for an initial amount of USD 100 million and a term of 2.25 years.
- 25,540,302 Common Shares purchased by a subsidiary of the Corporation on June 2, 2017, pursuant to the offer made to shareholders at C$4.77/share.

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OPERATIONS REVIEW

Business Overview

Since first listing IPC on April 24, 2017 in Canada and Sweden, we have been focused on delivering operational excellence, demonstrating financial resilience in a low oil price environment, maximizing the value of our resource base and assessing numerous acquisition opportunities.

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. We have made excellent progress during the third quarter on all fronts in delivering on that strategy.

Delivering Operational Excellence
During the third quarter of 2017, our assets have continued to deliver ahead of expectation with production of 9,200 boepd, representing a 7 percent increase above our third quarter mid-point guidance. For the nine months ended September 30, 2017, production was 10,400 boepd, 4 percent ahead of mid-point guidance.

This has been driven by a good performance across all of our assets in Malaysia, France and the Netherlands. A world class uptime performance on the Bertam FPSO of in excess of 99 percent continued during the third quarter (excluding the planned shutdown). It is remarkable that such a performance has been delivered since Bertam started producing back in April 2015.

The planned Bertam FPSO shutdown was successfully completed during the third quarter safely, on schedule and within budget.

As a result of the strong year to date performance we are revising our full year production guidance from 9,000 to 11,000 boepd, to 10,000 to 10,500 boepd.

Given the good production performance and lower operating costs we are reducing our operating cost per barrel guidance from USD 17.20 to USD 16.20. We are also revising downwards our capital expenditure guidance from USD 38 million to USD 33 million following the latest view on timing of the infill drilling program in Malaysia and identified cost savings.

Financial resilience in a low oil price environment
IPC is highly free cash flow generative given the low cost nature of our assets. In February, we guided full year operating cash flow generation of USD 82 to USD 140 million (assuming a Dated Brent oil price of USD 40 to 60 per barrel and mid-point production guidance of 10,000 boepd). For the nine months ended September 30, 2017, operating cash flow generation is ahead of guidance at USD 101.2 million based upon a first nine months average Dated Brent oil price of close to USD 52 per barrel.

On the liquidity front, IPC put in place a USD 100 million reserve based lending facility to facilitate the share purchase offer. The primary objective of the offer was to remove Statoil as a large non-core shareholder and a potential major overhang on the stock. Approximately 25.5 million shares were purchased for a consideration of USD 90 million and subsequently cancelled through an internal reorganization. In addition IPC used the credit facility to partly fund a deposit of CAD 40 million as part of the transaction to acquire the Suffield assets from Cenovus during September. Following the completion of the share purchase offer and payment of the Canadian deposit, our net debt level was USD 47.2 million by the end of the third quarter, demonstrating the robust free cash flow generation from IPC at relatively low oil prices.

Maximizing the value of our resource base
We believe that we can add significant value to IPC's existing assets through a renewed focus on organic growth. Following a re-evaluation of our assets during the second quarter, we reported a total best estimate contingent resource base of 17.5 MMboe as at June 30, 2017. This represents an impressive 59 percent of our year end 2016 reported 2P reserve number of 29.4 MMboe.

The drilling of two additional infill wells on the Bertam field in Malaysia was approved during the second quarter. Good progress has been made during the third quarter with partner approval having been secured and a rig contract executed. Drilling is expected to commence during the fourth quarter. These infill wells are expected to generate significant returns given an essentially fixed operating cost base on the Bertam field. Drilling costs have fallen by around one-third compared to wells drilled on the Bertam field in 2014/15 and no facilities capital investment is required as the Bertam wellhead platform was designed to accommodate additional wells. The infill wells will target net best estimate contingent resources of 1.7 MMboe. These wells are forecast to breakeven at below USD 20 per barrel and, based on the forward oil price curve, to pay back in around eight months. From a production perspective, contribution from these infill wells is expected to enable IPC to more than offset the natural decline from our assets in Malaysia, France and the Netherlands as we move into 2018.

Given the ongoing study work on the Bertam field and the attractive economics of infill wells and near field developments, we believe that it is likely there will be further development drilling on the Bertam fields beyond the currently planned two well program.

In France we continue work on optimizing the Vert La Gravelle development plan. This project was started back in 2013 by Lundin Petroleum with the drilling of two wells and installation of all the facilities, however was suspended as a result of Lundin Petroleum's capital allocation priorities. We are currently evaluating the potential to apply horizontal drilling on this project for the first time in our Paris Basin Rhaetian fields and this could have a wider application in our other fields by lifting initial well productivity.

We have also successfully completed the acquisition of the first ever large scale 3D seismic acquisition on one of our largest producing fields in the Paris Basin, the Villeperdue field. For many years our subsurface team has observed lower water cuts of around 60 percent in the two western most producers, whereas other wells to the east of the field have been producing with water cuts of around 95 percent on average. We believe there may be upside in developing the western extension of the field and the 3D seismic acquisition is expected to de-risk this through a combination of better imaging of the structure and imaging of reservoir attributes. In addition it will allow us to better define the structure of the Villeperdue Deep prospect in the Triassic Rhaetian formation which is a formation produced and well understood in other parts of the Paris Basin. The net capital cost for the 3D seismic acquisition is forecast at USD 4.1 million, and the acquisition was successfully completed during the third quarter on schedule and within budget. The focus will now turn to processing and interpretation with initial seismic interpretation results expected during the first half of 2018.

Growth from Acquisition

During the third quarter IPC announced the transformational acquisition of the Suffield assets from Cenovus in Alberta, Canada. Suffield is a high quality conventional asset that has been operated safely and efficiently by Cenovus for many years and we are pleased to have reached this agreement to acquire these producing assets as Cenovus focuses on its oil sands and Deep Basin assets. This acquisition fits perfectly with IPC's strategy of leveraging our existing producing asset base as a platform for value accretive acquisitions of long-life, low-decline producing assets in stable jurisdictions with upside development potential.

The Suffield oil and natural gas assets are held over a large, contiguous land position of 800,000 net acres of shallow natural gas rights and 100,000 net acres of oil rights in southern Alberta. IPC has agreed to acquire 100% operatorship (98.8% working interest) in the oil and natural gas assets which are forecast to produce an average of approximately 6,900 (bopd) and approximately 102 million standard cubic feet of natural gas per day during 2017, for a total average of approximately 24,000 (boepd). These producing fields have low production costs and significant future development potential from a combination of low risk development drilling, well stimulation and enhanced oil recovery (EOR) opportunities, which have not been undertaken for a number of years due to Cenovus' capital allocation priorities.

Gross 2P reserves as at January 1, 2018 of the Suffield/Alderson assets to be acquired are 99.6 million MMboe and best estimate contingent resources of 46.1 MMboe. The transaction consideration of CAD 512 million (subject to closing adjustments and to certain additional contingent consideration) will be fully funded from internally generated cash flow and exiting and new reserve based lending facilities. The financing package has been fully underwritten by BMO Capital Markets.

We are particularly pleased to have signed such a material acquisition of high quality conventional oil and gas assets only five months since IPC was formed. This asset platform, together with our existing assets, provides IPC with a solid cash flow generative, low cost portfolio of mostly operated assets. It is noteworthy that we have been able to deliver such a transaction with no equity dilution.

It is expected that the transaction will complete by the end of the year.

HSE Performance

Safety performance in the first nine months of 2017 has been outstanding with no major incidents, injuries to personnel or spills /releases to the environment. Safety remains a priority for all operational and asset teams and we are constantly looking at ways to improve performance and ensure that our operations have no impact on personnel, assets or the environment.

Swedish Listing

IPC is progressing its plans to list its shares on the Nasdaq Stockholm, however given the materiality of the acquisition of the Suffield/Alderson assets in Canada, such listing will be delayed until after completion of this acquisition.

Operations Overview

Reserves and Resources
The IPC producing assets had 29.4 MMboe of 2P reserves as at 31 December 2016 as certified by an independent third party reserves auditor.

Production
Production for the IPC assets during the third quarter of 2017 amounted to 9.2 Mboepd and was above the midpoint of the production guidance by 7 percent. The production during the reporting period with comparatives was comprised as follows:

Production [1] in Mboepd	Three months ended September 30 2017	Three months ended September 30 2016	Nine months ended September 30 2017	Nine months ended September 30 2016	12 months ended December 30 2016
Crude oil					
Malaysia	5.7	8.9	6.7	8.7	8.6
France	2.4	2.5	2.5	2.6	2.6
Total crude oil production	**8.1**	11.4	**9.2**	11.3	**11.2**
Gas					
Netherlands	1.1	1.5	1.2	1.6	1.6
Total gas production	**1.1**	1.5	**1.2**	1.6	1.6
Total production	**9.2**	12.9	**10.4**	12.9	12.8
Quantity in MMboe	**0.85**	1.19	**2.85**	3.53	4.66

[1] *Excludes 1.17 MMboe produced by the Singa field, Indonesia, in 2016 prior to the sale of the asset in April 2016*

SOUTH EAST ASIA

Malaysia

Production in Mboepd	WI	Three months ended September 30 2017	Three months ended September 30 2016	Nine months ended September 30 2017	Nine months ended September 30 2016	12 months ended December 30 2016
Bertam	75%	**5.7**	8.9	**6.7**	8.7	8.6

Production
Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was ahead of forecast at 6.7 Mboepd. Reservoir performance for the Bertam field was also in line with expectation and facilities uptime for the reporting period was in excess of 99 percent. The planned shutdown was safely completed in line with expectations in July, and a successful startup allowed production ahead of forecast in the third quarter.

The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. Currently, the FPSO is provisionally flagged, with a statement of compliance until December 2017. IPC continues to progress various strategic options with regard to this issue. See "Risk Factors – FPSO Flagging Regulations in Malaysia" on page 25.

Capital Program

During the reporting period, work has continued on reservoir studies and identification of additional low risk infill and near field development opportunities to grow production in the years ahead. A full review of possible bypassed oil within the Bertam field was completed and five infill locations identified and ranked during the second quarter of 2017. From this study two infill locations were high graded, sanctioned for development and drilling remains on track to commence in the fourth quarter of 2017. These wells are expected to add best estimate contingent resources of 2.3 MMboe (gross) [1]. Net cash costs for these wells have reduced from the estimates in the second quarter due to rig and service rates being lower than originally budgeted. Breakeven analysis shows a positive return on investment at oil prices above USD 20 per boe and the investment payback period is around eight months based on forward curve oil price assumptions. During the third quarter, partner and Petronas approvals were received, with rig and contract awards made thereafter.

[1] Recovery of the contingent resources requires the drilling of two development horizontal wells tied-back to existing infrastructure.

A 3D seismic acquisition program was completed on the Bertam field in 1996, which was used during the development of the field and subsequent drilling activities. Reprocessing of this data set with the latest technology has been ongoing since early 2017, allowing for a full review of additional infill targets and the near field opportunity set with the aim to add low cost, low risk production into existing infrastructure. This study and analysis will continue over the remainder of 2017 and into 2018. The contingent resource estimates reported for Malaysia relate to announced drilling program of two infill locations in the producing Bertam field. For further information on the Bertam field, reference is made to the Final Prospectus. The product type is light crude oil. The risk and uncertainty associated with the Malaysia contingent resources is reduced because the two proposed infill wells are close to existing wells, with the main risk relating to competitive drainage from offset wells.

Exploration Blocks

An extension to the drill or drop decision on exploration Block PM328 was submitted in the first quarter to extend the decision by six months until September 2017, subject to approval from Petronas. A review of the prospective potential within this block has been completed and given the IPC strategic objectives, combined with the review, management has taken the decision to relinquish the block, and is currently awaiting Petronas approval.

During the reporting period applications for relinquishment of the exploration blocks SB307 and SB308 have been submitted and approved by Petronas.

No commitments are outstanding on any blocks in Malaysia.

CONTINENTAL EUROPE

		Three months ended September 30		Nine months ended September 30		12 months ended December 30
Production in Mboepd	WI	**2017**	2016	**2017**	2016	2016
France						
- Paris Basin	100% [1]	2.0	2.1	2.1	2.2	2.2
- Aquitaine	50%	0.4	0.4	0.4	0.4	0.4
Netherlands	Various	1.1	1.5	1.2	1.6	1.6
		3.5	4.0	**3.7**	4.2	4.2

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

France

Net production during the reporting period from France was slightly above forecast at 2.5 Mboepd. Production performance in line with expectations has been achieved across all fields in the reporting period, in particular the Villeperdue field which is the largest in IPC's French portfolio.

Organic Growth
IPC recognizes significant development upside in the Paris Basin. In parallel with maturing the contingent resources we have also been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base. Following a detailed evaluation and ranking exercise of the entire portfolio of opportunities we have prioritized the Vert La Gravelle re-development optimization and the Villeperdue West opportunities.

The Vert La Gravelle field has been on production since the mid 1980s and has long been recognized as a field with waterflood and development drilling upside. A field re-development project was sanctioned in 2014 however as a result of Lundin Petroleum's capital re-allocation priorities, the project was postponed after the construction and commissioning of the facilities and the drilling of the first two wells. IPC is taking the opportunity to revisit the development concept sanctioned in 2014 in particular we are investigating the merits of applying horizontal well technology as a means to optimize value. The unoptimized development concept is already reflected in our 2P reserves base.

Villeperdue West development is the single largest contingent resource opportunity in the IPC portfolio at 4.1 MMboe of best estimate contingent resources. The concept is to extend the development drilling to the west into an area that was considered to be water bearing when the initial field development was executed in the 1980s. Production trends on the west extension combined with our mapping and geologic assessment point towards significant bypassed oil potential which can be developed and tied into existing infrastructure. There remains structure and reservoir risk which is being addressed through the acquisition of 79 km2 of high resolution three dimensional seismic.

The 3D seismic acquisition was completed safely and within budget in October 2017.

Seismic processing, interpretation and subsequent reservoir development studies will continue through 2017 and into 2018 as a step towards monetizing this resource. The seismic survey will also improve the structural definition of the Villeperdue Deep prospect. Un-risked breakeven analysis on the Villeperdue West project is very attractive at below USD 30 per barrel.

The contingent resource estimates reported for France relate to development drilling and waterflood optimization opportunities. For further information on the Corporation's French fields in the Paris Basin (operated) and the Aquitaine Basin (non-operated), reference is made to the Final Prospectus In all cases, the product type is light crude oil. The risk and uncertainty associated with the contingent resources in France is largely due to limited seismic coverage and understanding of structural extent of the fields. To recover the contingent resources, the drilling of development wells and, in some instances, the modification of existing production facilities would be required. Project development timing for the highest ranked opportunities will potentially be in the next two to five years with the remaining within the next ten years. In all cases, the contingent resources require a definitive development plan and approval of the plan to mature from contingent resources to reserves.

The Netherlands
Net production from the Netherlands fields during the reporting period was ahead of forecast at 1.2 Mboepd.

Offshore, during the third quarter, the installation and start-up of the new 10" pipeline from L4 to K6 was successfully completed and production from the L7 fields was shut-in as planned in August. The facilities have now been declared hydrocarbon free and put on light-house mode. Slootdorp production is still constrained due to permitting restrictions and the operator is awaiting approval to increase production back to full rates.

Onshore, the compressor installation at the Mildam junction in the Gorredijk license was successfully completed and is fully operational. The Nieuwehorne-2 exploration well has been successfully drilled during Q3 with hydrocarbons found in 2 intervals. A well test is currently being carried out to establish the productivity of the well and reservoir.

FINANCIAL REVIEW

Financial Results

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

	Nine months ended September 30	Quarterly financial information			Nine months ended September 30	Quarterly financial information		
US$ Thousands	**2017**	**Q3 2017**	Q2 2017	Q1 2017	2016	Q3 2016	Q2 2016	Q1 2016
Revenue	**148,354**	**47,926**	48,496	51,932	150,288	48,498	55,568	46,222
Gross profit/(loss)	**35,287**	**7,256**	10,361	17,670	8,961	9,631	16,029	(16,699)
Net result	**13,746**	**2,172**	7,113	4,461	(19,623)	4,522	26,954	(51,099)
Earnings per share – USD[1]	**0.13**	**0.02**	0.07	0.04	(0.17)	0.04	0.24	(0.45)
Earnings per share fully diluted – USD[1]	**0.13**	**0.02**	0.07	0.04	(0.17)	0.04	0.24	(0.45)
Operating cash flow [2]	**101,212**	**28,893**	32,643	39,676	110,841	38,911	42,746	29,185
EBITDA [2]	**95,876**	**26,440**	30,049	39,387	108,917	38,439	43,005	27,473
Net debt [2]	**47,241**	**47,241**	35,348	(20,082)	(8,443)	(8,443)	(19,235)	(13,410)

[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 20 under "Non-IFRS measures"*

Summarized interim condensed consolidated balance sheet information is as follows:

US$ Thousands	**September 30, 2017**	December 31,2016
Non-current assets	454,522	484,923
Current assets	116,745	87,109
Total assets	**571,267**	572,032
Total non-current liabilities	216,340	140,197
Current liabilities	61,070	26,739
Total liabilities	**277,410**	166,936
Net assets (liabilities)	**293,857**	405,096
Working capital (including cash)	**55,675**	60,370

Segment Information

IPC operates within several geographical areas. Operating segments are reported at country level which is consistent with the internal reporting provided to IPC management. The following tables present segment information regarding; revenue, production costs, exploration and business development costs, impairment costs of oil and gas properties and gross profit and certain asset and liability information.

	Three months ended – September 30, 2017				
US$ Thousands	Malaysia	France	Netherlands	Other	Total
Crude oil	29,847	9,765	10	–	**39,622**
NGLs	–	–	86	–	**86**
Gas	–	–	3,482	–	**3,482**
Net sales of oil and gas	**29,847**	**9,765**	**3,578**	**–**	**43,190**
Change in under/over lift position	–	291	(178)	–	**113**
Other operating revenue	3,910	266	386	61	**4,623**
Revenue	**33,757**	**10,322**	**3,786**	**61**	**47,926**
Production costs	(11,902)	(4,955)	(2,305)	–	**(19,162)**
Depletion	(7,289)	(3,508)	(1,304)	–	**(12,101)**
Depreciation of other assets	(8,047)	–	–	–	**(8,047)**
Exploration and business development costs	(64)	(1)	–	(1,295)	**(1,360)**
Impairment costs	–	–	–	–	**–**
Gross profit/(loss)	**6,455**	**1,858**	**177**	**(1,234)**	**7,256**

	Three months ended – September 30, 2016				
US$ Thousands	Malaysia	France	Netherlands	Other [1]	Total
Crude oil	31,233	8,962	22	–	40,217
NGLs	–	–	117	–	117
Gas	–	–	3,552	–	3,552
Net sales of oil and gas	31,233	8,962	3,691	–	43,886
Change in under/over lift position	–	3	(43)	–	(40)
Other operating revenue	3,799	294	378	181	4,652
Revenue	35,032	9,259	4,026	181	48,498
Production costs	(3,133)	(4,209)	(2,283)	–	(9,625)
Depletion	(15,961)	(3,546)	(2,503)	–	(22,010)
Depreciation of other assets	(7,733)	–	–	–	(7,733)
Exploration and business development costs	(67)	(8)	–	576	501
Gross profit/(loss)	8,138	1,496	(760)	757	9,631

[1] *Mainly relates to the Singa field, Indonesia, which was sold in April 2016*

	Nine months ended – September 30, 2017				
US$ Thousands	**Malaysia**	**France**	**Netherlands**	**Other**	**Total**
Crude oil	88,180	35,509	48	–	**123,737**
NGLs	–	–	284	–	**284**
Gas	–	–	11,249	–	**11,249**
Net sales of oil and gas	**88,180**	**35,509**	**11,581**	**–**	**135,270**
Change in under/over lift position	–	89	(571)	–	**(482)**
Other operating revenue	11,603	805	937	221	**13,566**
Revenue	**99,783**	**36,403**	**11,947**	**221**	**148,354**
Production costs	(22,544)	(18,749)	(5,770)	–	**(47,063)**
Depletion	(25,794)	(10,879)	(3,876)	–	**(40,549)**
Depreciation of other assets	(23,713)	–	–	–	**(23,713)**
Exploration and business development costs	(6)	(25)	–	(1,875)	**(1,906)**
Impairment costs	164	–	–	–	**164**
Gross profit/(loss)	**27,890**	**6,750**	**2,301**	**(1,654)**	**35,287**

	Nine months ended – September 30, 2016				
US$ Thousands	**Malaysia**	**France**	**Netherlands**	**Other [1]**	**Total**
Crude oil	85,323	30,229	42	–	115,594
NGLs	–	–	357	–	357
Gas	–	–	10,946	9,269	20,215
Net sales of oil and gas	85,323	30,229	11,345	9,269	136,166
Change in under/over lift position	–	228	(299)	–	(71)
Other operating revenue	11,305	921	1,258	709	14,193
Revenue	96,628	31,378	12,304	9,978	150,288
Production costs	(15,048)	(16,498)	(7,731)	(1,362)	(40,639)
Depletion	(46,285)	(10,703)	(7,817)	–	(64,805)
Depreciation of other assets	(23,377)	–	–	–	(23,377)
Exploration and business development costs	(13,053)	(39)	–	586	(12,506)
Gross profit/(loss)	(1,135)	4,138	(3,244)	9,202	8,961

[1] *Mainly relates to the Singa field, Indonesia, which was sold in April 2016*

Three and nine months ended September 30, 2017 Review

Revenue

Total revenue amounted to USD 47,926 thousand for Q3 2017 compared to USD 48,498 thousand for Q3 2016 and USD 148,354 thousand for the first nine months of 2017 compared to USD 150,288 thousand for the first nine months of 2016 and is analyzed as follows:

	Three months ended September 30		Nine months ended September 30	
US$ Thousands	**2017**	2016	**2017**	2016
Crude oil sales	39,622	40,217	123,737	115,594
Gas and NGL sales	3,568	3,669	11,533	20,572
Change in under/overlift position	113	(40)	(482)	(71)
Other operating revenue	4,623	4,652	13,566	14,193
Total revenue	**47,926**	48,498	**148,354**	150,288

The components of total revenue for the three and nine months ended 30 September 2017 and September 30, 2016, respectively are detailed below:

Crude oil sales

	Three months ended – September 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	29,847	9,765	10	**39,622**
- Quantity sold in bbls	545,123	183,542	210	**728,875**
- Average price realized US$ per bbl	54.75	53.20	49.50	**54.36**

	Three months ended – September 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	31,233	8,962	22	40,217
- Quantity sold in bbls	669,595	196,510	583	866,688
- Average price realized US$ per bbl	46.64	45.61	37.09	46.40

Crude oil sales were 1 percent lower in Q3 2017 compared to Q3 2016 attributable to 16 percent lower sales volumes during the quarter partly offset by an increase in the oil price realized. The realized sales price is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 52.08/ bbl in Q3 2017 and USD 45.86/bbl in Q3 2016.

	Nine months ended – September 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	88,180	35,509	48	**123,737**
- Quantity sold in bbls	1,614,960	705,429	1,097	**2,321,486**
- Average price realized US$ per bbl	54.60	50.34	43.57	**53.30**

	Nine months ended – September 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	85,323	30,229	42	115,594
- Quantity sold in bbls	1,993,892	719,278	1,228	2,714,398
- Average price realized US$ per bbl	42.79	42.03	33.82	42.59

Crude oil sales were 7 percent higher for the first nine months of 2017 compared to the first nine months of 2016 due to a 25 percent increase in the average sales price achieved partly offset by a 14 percent decrease in the volumes sold. The realized sales price is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 51.84/bbl in the first nine months of 2017 compared to USD 41.88/bbl for the comparative period. There were eight cargoes sold in Malaysia during the first nine months of 2017 compared to nine cargoes in the comparative period, primarily as a result of the lower production volumes.

Gas and NGL sales

	Three months ended – 30 September 2017				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in US$ thousands	–	–	3,568	–	**3,568**
- Quantity sold in mcf	–	–	668,172	–	**668,172**
- Average price realized US$ per mcf	–	–	5.34	–	**5.34**

	Three months ended – 30 September 2016				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in US$ thousands	–	–	3,669	–	3,669
- Quantity sold in mcf	–	–	853,183	–	853,183
- Average price realized US$ per mcf	–	–	4.30	–	4.30

	Nine months ended – 30 September 2017				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in US$ thousands	–	–	11,533	–	**11,533**
- Quantity sold in mcf	–	–	2,124,055	–	**2,124,055**
- Average price realized US$ per mcf	–	–	5.43	–	**5.43**

	Nine months ended – 30 September 2016				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in US$ thousands	–	–	11,303	9,269	20,572
- Quantity sold in mcf	–	–	2,635,152	1,069,066	3,704,218
- Average price realized US$ per mcf	–	–	4.29	8.67	5.55

The gas sales revenue for the three and nine months ended September 30, 2016 includes revenue in respect of the Singa field in Indonesia. The Singa field was sold in April 2016. The average price realized for Singa gas revenue was based on a fixed contract price and is therefore higher compared to the Dutch assets where the price realized is based on market prices. Dutch gas volumes sold in the nine months ended September 30, 2017 are 19 percent lower than the comparative period due to the naturally declining production, but this has been offset by a 27 percent higher realized gas price.

Other operating revenue

Other operating revenue amounted to USD 4,623 thousand for Q3 2017 compared to USD 4,652 thousand for Q3 2016 and USD 13,566 thousand for the first nine months of 2017 compared to USD 14,193 thousand for the first nine months of 2016. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam facility to the Bertam field in Malaysia, but also includes tariff income from France and the Netherlands and income for maintain strategic inventory levels in France.

Production costs

Production costs including inventory movements amounted to USD 19,162 thousand for Q3 2017 compared to USD 9,625 thousand for Q3 2016 and USD 47,063 thousand for the first nine months of 2017 compared to USD 40,639 thousand for the first nine months of 2016 and is analyzed as follows:

	Three months ended – September 30, 2017					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	19,336	5,951	2,305	–	(11,730)	**15,862**
USD/boe[2]	37.22	26.68	21.88	–	n/a	**18.71**
Change in inventory position	4,296	(996)	–	–	–	**3,300**
Production costs	**23,632**	**4,955**	**2,305**	**–**	**(11,730)**	**19,162**

	Three months ended – September 30, 2016					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	16,411	5,241	2,283	–	(11,729)	12,206
USD/boe[2]	19.94	22.77	16.14	n/a	n/a	10.22
Change in inventory position	(1,549)	(1,032)	–	–	–	(2,581)
Production Costs	14,862	4,209	2,283	–	(11,729)	9,625

	Nine months ended – September 30, 2017					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	54,508	17,010	5,770	–	(34,808)	**42,480**
USD/boe[2]	29.65	25.32	17.16	–	n/a	**14.92**
Change in inventory position	2,844	1,739	–	–	–	**4,583**
Production costs	**57,352**	**18,749**	**5,770**	**–**	**(34,808)**	**47,063**

	Nine months ended – September 30, 2016					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	53,808	16,480	7,731	1,362	(34,935)	44,446
USD/boe[2]	22.54	23.51	17.63	7.00	n/a	11.94
Change in inventory position	(3,825)	18	–	–	–	(3,807)
Production costs	49,983	16,498	7,731	1,362	(34,935)	40,639

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

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

[3] *Included in the Malaysia production 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 to USD 10.72 and USD 7.91 for Malaysia for the nine months ended September 30, 2017 and 2016 respectively.*

Production costs excluding inventory movements (operating costs)

Production costs excluding inventory movements (operating costs) amounted to USD 15,862 thousand for Q3 2017, compared to USD 12,206 thousand for Q3 2016 and USD 42,480 thousand for the first nine months of 2017 compared to USD 44,446 thousand for the first nine months of 2016. Included in Q3 2017 are costs of USD 3,309 thousand associated with the Bertam planned shutdown. Included in the first nine months of 2016 is USD 2,267 thousand for the workover of two shut-in production wells on the Bertam field and USD 1,362 which relates to the Singa field, Indonesia, which was sold in April 2016. These items account for a significant part of the 4 percent reduction in the costs in the first nine months of 2017 compared to 2016, along with reduced project and maintenance activities in the Netherlands in 2017. Despite the reduction in the costs, the cost per boe increased for the nine months ended September 30, 2017 compared to 2016 due to the lower production volumes in 2017.

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. The inventory is 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 income statement. In the Aquitaine Basin, France, due to the relatively low level of production from the Aquitaine fields, there is only the one lifting forecast in 2017 which was lifted in March.

Depletion

The total depletion charge amounted to USD 12,101 thousand for Q3 2017 compared to USD 22,010 thousand for Q3 2016 and USD 40,549 thousand for the first nine months of 2017 compared to USD 64,805 thousand for the first nine months of 2016. The depletion charge per country is analyzed in the following tables:

	Three months ended – September 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in US$ thousands	7,289	3,508	1,304	**12,101**
Depletion US$ per boe	14.03	15.73	12.38	**14.27**

	Three months ended – September 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in US$ thousands	15,961	3,546	2,503	22,010
Depletion US$ per boe	19.39	15.41	17.69	18.42

	Nine months ended – September 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in US$ thousands	25,794	10,879	3,876	**40,549**
Depletion US$ per boe	14.03	16.19	11.53	**14.25**

	Nine months ended – September 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in US$ thousands	46,285	10,703	7,817	64,805
Depletion US$ per boe	19.39	15.20	17.82	17.41

The depletion rates for the Bertam field, Malaysia and the Dutch gas fields have reduced significantly in 2017 compared to 2016 due mainly to the reserves upgrades at the end of 2016. The depletion rate is calculated for each of the French and Dutch producing assets and therefore the rates shown in the table depend on the relative production contribution of each asset. The depletion charge is calculated by applying the depletion rate per boe to the volumes produced in the period. Note that there was no depletion charge in 2016 for the Singa field, Indonesia as it was held as an asset for sale during the period.

Depreciation of other assets

The total depreciation of other assets amounted to USD 8,047 thousand for Q3 2017 compared to USD 7,733 thousand for Q3 2016 and USD 23,713 thousand for the first nine months of 2017 compared to USD 23,377 thousand for the first nine months of 2016. 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.

Exploration and business development costs

Total expensed exploration and business development costs amounted to USD 1,360 thousand for Q3 2017 compared to a USD 501 thousand credit for Q3 2016 and USD 1,906 thousand for the first nine months of 2017 compared to USD 12,506 thousand for the first nine months of 2016. The costs relate to unsuccessful exploration and evaluation costs and expenses related to business development activities. Exploration and evaluation costs are capitalized as they are incurred and expensed when their recoverability is determined highly uncertain (for example, an unsuccessful exploration well is drilled). Expensed costs in the first nine months of 2017 mainly represent the costs of business development activities. The significant exploration costs in 2016 mainly related to the unsuccessful exploration wells drilled on the SB307/308 licence in Malaysia during the first quarter. The credit in the three months ended September 30, 2016, mainly related to the reversal of an over estimate of the cost of the unsuccessful Malaysian exploration campaign expensed in the first quarter of 2016 and the fourth quarter of 2015.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 2,545 thousand for Q3 2017 compared to USD 774 thousand for Q3 2016 and USD 6,325 thousand for the first nine months of 2017 compared to USD 1,726 thousand for the first nine months of 2016. Up until the Spin-Off date, 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 IPC Group's corporate structure and management post Spin-Off.

Net financial items

Net financial items for Q3 2017 amounted to USD 1,263 thousand compared to USD 4,110 thousand for Q3 2016 and USD 12,716 thousand for the first nine months of 2017 compared to USD 21,123 thousand for the first nine months of 2016. Included in the amount for the first nine months 2017 is a largely non-cash foreign exchange loss of USD 8,719 mainly resulting on USD intra-group loan funding balances held by a subsidiary with a functional currency of Euro. Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. In addition, the unwinding of the discount rate on the asset retirement obligations amounted to USD 2,641 thousand for the nine months of 2017. Asset retirement obligations estimates are discounted to a present value when reflected in the balance sheet and the discounting is unwound through the income statement.

Income tax

The corporate income tax charge for Q3 2017 was USD 1,276 thousand compared to USD 225 thousand for Q3 2016 and USD 2,500 thousand for the first nine months of 2017 compared to USD 2,283 thousand for the first nine months of 2016. There was a current tax charge of USD 79 in the first nine months of 2017 compared to a USD 1,192 thousand credit in the comparative period mainly related to a Dutch petroleum tax refund. The deferred tax charge for the first nine months of 2017 amounted to USD 2,421 thousand compared to USD 3,475 thousand for the first nine months of 2016 which included a deferred tax charge relating to the Singa field, Indonesia, which was sold in April 2016.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first nine months of 2017 was as follows:

US$ Thousands	Malaysia	France	Netherlands	Total
Development	3,054	2,450	1,508	**7,012**
Exploration and evaluation	163	3,340	562	**4,065**
	3,217	5,790	2,070	**11,077**

The exploration and evaluation cost in France mainly relates to the acquisition of the 3D seismic in the Villeperdue field.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 130,339 thousand as at September 30, 2017, which included USD 128,755 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.

Financial Position and Liquidity

Financing

On April 20 2017, certain IPC subsidiaries, with IPC as guarantor, entered into a 2.25-year senior secured USD 100 million reserve-based lending credit facility, which was used to fund the offer to purchase common shares of IPC announced on April 24, 2017.

The credit facility was initially drawn for USD 80.0 million on May 31, 2017 to partly fund the share purchase offer made to all shareholders totaling USD 90.6 million. In addition, USD 30.0 million was drawn in September 2017 to partly fund a CAD 40.0 million deposit in respect of the Suffield asset acquisition. Cash flow generated from the assets has been used to reduce the amount drawn under the credit facility to USD 65.0 million as at September 30, 2017. Net debt as at September 30, 2017 is USD 47.2 million after deducting cash balances from the amount drawn under the facility. The increase compared to the USD 35.3 million reported at June 30, 2017 is mainly attributable to the deposit amount drawn partly offset by cash flow generated from the assets.

Cash and cash equivalents held amounted to USD 17.8 million as at September 30, 2017. Cash balances are held to meet ongoing operational funding requirements in the different countries.

Since January 1, 2017, USD 31.4 million of cash generated by the Group had been funded to Lundin Petroleum up until the Spin-Off and is shown in the interim condensed consolidated statement of cash flow. This amount was offset against the agreed net working capital amount of USD 56.9 million owing by the Group to Lundin Petroleum as at December 31, 2016 which was comprised of trade receivables, hydrocarbon inventories, well supplies and cash, net of trade payables and accruals. Further repayments of the working capital were made during the second and third quarter of 2017 and the net outstanding balance as at September 30, 2017 of USD 23.4 million is due to Lundin Petroleum before the end of June 2018.

In connection with the financing of the Suffield acquisition, IPC has commitment from banks for new CAD 325 million borrowing base credit facilities in Canada and to an increased existing reserve-based lending credit facility from USD 100 million to USD 200 million. The financing facilities will be executed on closing of the acquisition which is expected to be before the end of the year.

Working Capital

As at September 30, 2017, the Group had a net working capital balance including cash of USD 55,675 thousand compared to USD 60,370 thousand as at December 31, 2016. The main movements in working capital during the nine months ended September 30, 2017 is the inclusion of the deposit in relation to the Suffield acquisition of USD 32,632 thousand and USD 23,429 thousand working capital residual liability to Lundin Petroleum following the Spin- Off. The amounts are derived from the face of the combined carve-out balance sheet and the change in working capital differs to the amount stated in the combined carve-out 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 issuers. 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 Corporation'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 Corporation'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 issuers. 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 on a per boe basis 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.

"Operating cost" is calculated as production costs excluding any change in the inventory position and is used to analyze the cash cost of producing the oil and gas volumes.

"Net debt" is calculated as bank loans less cash and cash equivalents.

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Three months ended September 30		Nine months ended September 30	
US$ Thousands	**2017**	2016	**2017**	2016
Revenue	**47,926**	48,498	**148,354**	150,288
Production costs	**(19,162)**	(9,625)	**(47,063)**	(40,639)
Current tax	**129**	37	**(79)**	1,192
Operating cash flow	**28,893**	38,911	**101,212**	110,841

EBITDA

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

	Three months ended September 30		Nine months ended September 30	
US$ Thousands	**2017**	2016	**2017**	2016
Net result	**2,172**	4,522	**13,746**	(19,623)
Net financial items	**1,263**	4,110	**12,716**	21,123
Income tax	**1,276**	225	**2,500**	2,283
Depletion	**12,101**	22,010	**40,549**	64,805
Depreciation of other assets	**8,047**	7,733	**23,713**	23,377
Exploration and business development costs	**1,360**	(501)	**1,906**	12,506
Impairment costs	–	–	**(164)**	–
Depreciation included in general, administration and depreciation expenses [1]	**221**	340	**910**	994
Sale of assets (non-recurring)	**–**	**–**	**–**	3,452
EBITDA	**26,440**	38,439	**95,876**	108,917

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

Operating costs

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

	Three months ended September 30		Nine months ended September 30	
US$ Thousands	**2017**	2016	**2017**	2016
Production costs	**19,162**	9,625	**47,063**	40,639
Change in inventory position	**(3,300)**	2,581	**(4,583)**	3,807
Operating costs	**15,862**	12,206	**42,480**	44,446

Net debt

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

US$ Thousands	**September 30, 2017**	December 31, 2016
Bank loans	**65,000**	– [1]
Cash and cash equivalents	**(17,759)**	(13,410)
Net debt	**47,241**	(13,410)

[1] *IPC was spun-off from Lundin Petroleum with no external bank loans*

Off-balance Sheet Arrangements

As at September 30, 2017 IPC, through its subsidiary IPC Malaysia BV, had issued bank guarantees to the customs authorities for an amount of USD 387 thousand.

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. The total number of common shares issued and outstanding in IPC is now 87,921,846.

Nemesia S.à.r.l., an investment company wholly owned by a Lundin family trust, owns 29,062,512 common shares in IPC. In addition, an investment company wholly owned by a trust whose settlor is Ian H. Lundin, owns a further 3,517,326 common shares.

In addition, IPC has 117,485,389 outstanding class A preferred shares, issued as a part of an internal corporate structuring to a wholly-owned subsidiary of IPC. Such preferred shares are not listed on any stock exchange and do not carry the right to vote on matters to be decided by the holders of IPC's common shares.

IPC has 1,856,600 stock options and 1,307,359 IPC transitional PSP and RSP awards granted in connection with the Spin-off, all of which were outstanding as of November 6, 2017.

Contractual Obligations and Commitments

The 2017 discretionary capital program was budgeted at USD 7.8 million for development costs and USD 2.2 million for exploration and appraisal costs. 50 percent of this budget was assigned to the French assets, 29 percent to the Dutch assets and 21 percent to Malaysia. Following approval of the Bertam infill wells, Malaysia and the 3D seismic acquisition in France, the 2017 capital program guidance was revised to USD 38 million as at the end of Q2 2017. Following the latest view on the timing of the infill drilling program in Malaysia, the 2017 capital expenditure guidance has been revised to USD 33 million.

The Bertam field (IPC working interest of 75%) has leased the FPSO Bertam, which is fully owned by another Group company, for an initial period of six years commencing April 2015.

Critical Accounting Policies and Estimates

In connection with the preparation of the Corporation's interim condensed consolidated combined carve-out 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 at the date of the Spin-Off, the Corporation had a residual liability for working capital owed to Lundin Petroleum AB of USD 27,429 thousand which has been reduced to USD 23,429 thousand as at September 30, 2017. This amount is reflected as a current liability as it is due before the end of June 2018.

In addition, Lundin Petroleum has charged the Corporation USD 315 thousand in respect of office space rental and USD 1,052 thousand in respect of shared services provided since the Spin-Off date. IPC has charged Lundin Petroleum USD 448 thousand in respect of consultancy fees in 2017.

Financial Risk Management

As an international oil and gas exploration and production company, the Corporation 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 Corporation seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil price, interest rate and foreign exchange hedges. Financial instruments will be solely used for the purpose of minimizing risks in the business. As at September 30, 2017, the Corporation had not entered into any hedges.

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

Capital Management

The Corporation's objectives when managing capital are to safeguard the Corporation's ability to continue as a going concern and to meet its committed work program requirements in order to create shareholder value. The Corporation 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 Corporation'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, political instability or conflicts or actions by major oil exporting countries. Price fluctuations will affect the Corporation's financial position.

Based on analysis of the circumstances, the management assesses the benefits of forward hedging monthly sales contracts for the purpose of establishing cash flow. If management believes that a hedging contract will enhance cash flow then it may choose to enter into a commodity price hedge.

Currency Risk

The Corporation's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange for known costs in non-US dollar currencies to US dollar in advance so that future US dollar costs can be forecast with a reasonable degree of certainty. The Corporation 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 Corporation 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 Corporation may be exposed to third party credit risk through contractual arrangements with counterparties who buy the Corporation's crude products. The Corporation's policy is to limit credit risk by only entering into oil and gas sales agreements to major oil and gas and trading companies. Where it is determined that there is a credit risk for oil and gas sales, the Corporation's policy is to require an irrevocable letter of credit for the full value of the sale. The Corporation'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 Corporation faces. Additional risks and uncertainties not presently known to the Corporation or that the Corporation currently considers immaterial may also impair the business and operations of the Corporation and cause the price of the Common Shares to decline. If any of the following risks actually occur, the Corporation'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 Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. There is a risk that additional commercial quantities of oil and natural gas will not be discovered or acquired by the Corporation. 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 Corporation will not fully insure against all of these risks, nor are all such risks insurable. The Corporation 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 Corporation could incur significant costs.

Declines in Oil and Gas Commodity Prices: 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 Corporation's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Corporation's assets.

Operational Risks Relating to Facilities and Pipelines: The pipelines and facilities associated with the Corporation'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 Corporation'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 Corporation.

Uncertainties Associated with Estimating Reserves and Resource Volumes: There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and resources and the future cash flows attributed to such reserves. The reserves- associated cash flow information set forth herein are estimates only. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Corporation's assets will vary from estimates thereof and such variations could be material. Estimates of Proved 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 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.

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 and production activities, price, taxes, royalties and the exportation of oil and natural gas.

FPSO Flagging Regulations in Malaysia: The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. Currently, the FPSO is provisionally flagged, with a statement of compliance until December 2017 that allows it to offload crude in Malaysian waters. As the FPSO provides a significant revenue stream, a failure to resolve the flagging issue may result in a reduction of earnings for the Corporation and may also have a significant impact on offloading of crude from the FPSO Bertam.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions: The Corporation may make acquisitions and dispositions of businesses and assets in the ordinary course of business, including the proposed acquisition of the Suffield/Alderson assets. 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 Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. In addition, non-core assets may be periodically disposed of, so that the Corporation 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 Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Reliance on Third-Party Operators: The Corporation has partners in each of the licence, lease and PSC areas associated with the Corporation's assets. In some cases, including in the Aquitaine Basin in France and the Netherlands, the Corporation 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 Corporation'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 Corporation.

Reliance on Third-Party Infrastructure: The Corporation delivers the products associated with the Corporation's assets by gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation is able to produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. 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 Corporation's business financial condition, results of operations, cash flows and future prospects.

Credit Facility: The Corporation is party to the reserves based lending facility and expects to become a party to another similar facility. The terms of these facilities contain operating and financial covenants and restrictions on the ability of the Corporation 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 Corporation 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 Corporation.

Competition for Resources and Markets: The international petroleum industry is competitive in all its phases. The Corporation 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.

Hedging Strategies: From time to time, the Corporation 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 Corporation will not benefit from such increases. Similarly, from time to time, the Corporation 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 Corporation'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 Corporation or the Corporation's assets, some of which may be material. .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. 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 Corporation and its operations and financial condition.

Decommissioning, Abandonment and Reclamation Costs: The Corporation is responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of the Corporation'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 regulatory requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates.

Third-Party Credit Risk: The Corporation may be exposed to third party credit risk through the contractual arrangements associated with the Corporation'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 Corporation's assets, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Repatriation of Earnings: A significant portion of the revenue-generating operations of the Corporation'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 are not expected to have a material adverse effect on the Corporation, 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.

Litigation: In the normal course of the Corporation'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 Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

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

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

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.

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 Corporation'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 Corporation'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.

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 Corporation'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 Corporations internal control over financial reporting during the three and nine month periods ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, the Corporations internal control over financial reporting.

Control Framework

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In particular and without limitation, this MD&A contains forward-looking statements pertaining to the following:
- IPC's intentions with respect to and ability to execute its growth strategies;
- timing and ability of IPC to finance and complete the acquisition of the Suffield/Alderson assets;
- integration of the Suffield/Alderson-related operations and employees into IPC;
- forecasted operating costs of IPC for 2017;
- 2017 guidance with respect to organic and inorganic growth opportunities;
- the performance characteristics of the IPC asset base;
- IPC's oil and natural gas production levels and the overall composition of such production in 2017 and 2018;
- expected 2017 and 2018 activities of IPC;
- drilling plans and expected results, including proposed infill drilling in Malaysia and horizontal drilling in France;
- IPC's future financial capacity; and
- liquidation and relinquishment of legacy non-producing interests and non-active entities.

Actual results could differ materially from those anticipated in these forward-looking statements or information as a result of the risk factors set forth below and elsewhere in this MD&A:
- oil and gas exploration, development and production risks;
- declines in oil and gas commodity prices;
- operational risks relating to IPC's wells, facilities and pipelines;
- third-party risks relating to facilities and pipelines;
- uncertainties associated with estimating reserves and resource volumes;
- regulatory approvals and compliance;
- risks relating to flagging regulations in Malaysia;
- risks relating to IPC's ability to execute projects on time, on budget or at all, and to effectively market the oil and natural gas that it produces;
- failure to realize anticipated benefits of acquisitions and dispositions;
- IPC's reliance on third-party operators and third-party infrastructure;
- risks relating to changes in legislation and the regulatory environment;
- competition for resources and markets;
- climate change legislation;
- the Corporation's reliance on management and key personnel; and
- risks relating to fraud, bribery and corruption.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements or information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Although the forward-looking statements contained in this MD&A are based upon assumptions that IPC believes to be reasonable, IPC cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, IPC has made assumptions regarding, among other things: the Corporation will conduct its operations in a manner consistent with its expectations; future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future currency exchange and interest rates; the impact of increasing competition; general conditions in economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; the continuance of existing tax and regulatory regimes; future operating costs; availability of future sources of funding; and IPC's ability to conclude new transactions, including financings and acquisitions, in a satisfactory manner. IPC has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide investors with a more complete perspective on IPC's future operations and such information may not be appropriate for other purposes. IPC's actual results, performance or achievement could differ materially from those expressed in, or implied by, forward- looking statements in this MD&A and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits IPC will derive therefrom. These forward-looking statements are made as of the date of this MD&A and IPC disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

RESERVES AND RESOURCE DATA

The MD&A contains references to estimates of gross 2P reserves and best estimate contingent resources. Gross reserves and contingent resources are the total working interest reserves before the deduction of any royalties and including any royalty interest receivable.

Unless otherwise stated, reserve estimates and estimates of future net revenue are effective as of 31 December 2016 and were prepared by IPC in accordance with standards prescribed by National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators (NI 51-101) and audited by ERC Equipoise Ltd., an independent qualified reserves auditor.

Unless otherwise stated, the estimates of best estimate contingent resources contained in this MD&A are based on an evaluation of contingent resources that was prepared by a qualified reserves evaluator, as defined in NI 51-101. The reserves evaluator is not independent of IPC for the purposes of NI 51-101.

Reserves estimates and contingent resource estimates in respect of the Suffield/Alderson assets are based on the evaluation of these assets as at September 1, 2017 prepared by McDaniel, an independent qualified reserve evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's July 1, 2017 price forecasts. The volumes are reported from an economic reference date of December 31, 2017.

"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.

The MD&A contains certain oil and gas metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate the Acquisition and the performance of the assets to be acquired, however, such measures are not reliable indicators of the future performance of such assets and the actual future performance may not compare to the performance of such assets in previous periods and therefore such metrics should not be unduly relied upon.

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 continent 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.

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 Company'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.

The contingent resources disclosed in the MD&A in respect of the Suffield/Alderson assets are consolidated into three project categories – shallow gas development drilling, oil development drilling, and ASP expansion. In all cases the recovery of the resources would be via established technology, are based upon conceptual development plans, are classed in either sub-economic or economic category as discussed below, and in terms of project maturity are considered in all cases as having development unclarified status.

The contingent resources disclosed in this MD&A in respect of the Suffield/Alderson assets, including the risks related to such contingent resources, are further described in the press release related to the proposed Suffield acquisition dated September 25, 2017.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD	Canadian dollar
EUR	Euro
USD or US$	US dollar

Oil related terms and measurements

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
Mbbl	Thousand barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day.
MMbo	Thousand cubic feet
NGL	Natural gas liquid

[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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