Q4

International Petroleum Corporation

Management's Discussion and Analysis

Three months ended and year ended December 31, 2017

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Contents

Non-IFRS Measures

References are made in this MD&A to “operating cash flow” (OCF), “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt”/”net cash” which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See “Non-IFRS Measures” on page 20.

Forward-Looking Statements

Certain statements contained in this MD&A constitute “forward-looking statements” or “forward-looking information” (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", “forecast”, "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "budget" and similar expressions) are not statements of historical fact and may be "forward-looking statements".Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the “Cautionary Statement Regarding Forward-Looking Information” on page 28.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel’s January 1, 2018 price forecasts as referred to below.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of this assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported and aggregated by IPC in this MD&A as being as at December 31, 2017.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated February 26, 2018 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 consolidated financial statements and accompanying notes for the three months ended and year ended December 31, 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 completed on April 7, 2017. On April 24, 2017, the Spin-Off was completed and IPC's shares commenced trading on the Toronto Stock Exchange and Nasdaq First North under the ticker symbol "IPCO".

In September 2017, IPC announced the acquisition of the Suffield oil and gas assets in southern Alberta, Canada. The acquisition was completed on January 5, 2018.

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

Basis of Preparation

The MD&A and 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 and accordingly, prior to the Spin-Off date, the results have been carved out from the historical consolidated financial statements of Lundin Petroleum. Refer to the Financial Statements for additional information on the basis of preparation.

Financial information is presented in United States Dollars ("USD"). However, as the Group operates in Europe, 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"). Commencing in early 2018, certain liabilities of the Corporation are denominated in Canadian Dollars ("CAD").

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

	December 31, 2017		December 31, 2016	
	Average	Period end	Average	Period end
1 EUR equals USD	1.1293	1.1993	1.1066	1.0541
1 USD equals CAD	1.2982	1.2540	1.3256	1.3460
1 USD equals MYR	4.2994	4.0470	4.1455	4.4860

2017 HIGHLIGHTS

Business Development

Suffield Acquisition

- Completed the purchase of the conventional oil and natural gas assets in the Suffield and Alderson areas of southern Alberta, Canada from Cenovus Energy Inc. on January 5, 2018.

Operational Highlights

Production and Operating Costs

- Continued good production of 9,952 boepd for the fourth quarter of 2017 and 10,307 boepd for the full year 2017 (the reporting period"), three percent ahead of original full year mid-point Capital Markets Day (CMD) guidance.
- Operating costs[1] per boe 14 percent below original guidance at USD 16.15 for the reporting period (CMD - USD 18.75).

Resources and Projects

- More than quadrupled 2P reserves to 129.1 MMboe post acquisition in Canada.
- More than tripled best estimate contingent resources to 63.4 MMboe post acquisition in Canada.
- Completed the drilling of two infill wells in Malaysia with production commencing in January and February 2018.
- Reduced capital expenditure for the reporting period to USD 23 million due to the re-phasing of infill drilling costs into early 2018 and further cost savings (Q3 guidance USD 33 million).
- Completed acquisition of 79 km^2 of 3D seismic on the Villeperdue field in France in October 2017.
- Application made for permanent flagging status for the Bertam FPSO in Malaysia, awaiting final regulatory approval.

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

Financial Highlights

	Three months ended December 31		Year ended December 31	
USD Thousands	**2017**	2016	**2017**	2016
Revenue	**54,647**	59,592	**203,001**	209,880
Gross profit/(loss)	**13,471**	(114,600)	**48,758**	(105,639)
Net result	**8,977**	(76,097)	**22,723**	(95,720)
Operating cash flow [1]	**37,156**	42,083	**138,368**	152,924
EBITDA [1]	**33,383**	41,126	**129,259**	150,043
Net debt [1]	**26,321**	(13,410)	**26,321**	(13,410)

[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. This facility was amended on December 20, 2017, with effect from January 3, 2018, to an amount of USD 200 million and a term of 4.5 years to June 30, 2022.
- 25,540,302 Common Shares purchased by a subsidiary of the Corporation on June 2, 2017, pursuant to the share purchase offer made to shareholders at CAD 4.77 per share.

OPERATIONS REVIEW

Business Overview

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

Our vision and strategy from the outset was to use the IPC platform to build a new international upstream company focused on creating long term value for our shareholders, launched at a favorable time in the industry cycle to acquire and grow a significant resource base. We have made excellent progress during 2017 and into early 2018 on all fronts in delivering on that strategy.

Delivering Operational Excellence

During the fourth quarter of 2017, our assets have continued to perform well with good production of 9,952 boepd, in line with our mid-point CMD guidance. For the full year, production of 10,307 boepd was three percent ahead of our mid-point CMD 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 in excess of 99 percent continued during the fourth quarter (excluding the planned shutdown for infill drilling operations). It is remarkable that such a sustained performance has been delivered since Bertam started producing in April 2015.

In addition, lower than forecast operating costs have allowed us to deliver full year operating costs of USD 16.15 per boe, 14 percent below our CMD guidance.

Our full year capital expenditure of USD 23 million is USD 10 million lower than our latest guidance. The reduction is driven mainly by the re-phasing of infill drilling expenditure on the Bertam field from 2017 into the beginning of 2018 as well as further savings on the drilling campaign.

Financial resilience in a low oil price environment

IPC has delivered a robust financial performance during 2017. Following the spin-off from Lundin Petroleum, IPC was in the favourable position of being debt free and holding highly cash generative assets. In May, IPC decided to change the capital structure of the Corporation through a share purchase offer. The primary objective of the offer was to provide an orderly exit for Statoil as a large non-core shareholder and a potential major risk to liquidity of the stock. Approximately 25.5 million shares were purchased for a consideration of USD 90 million and subsequently cancelled through an internal reorganization, resulting in shareholder negative dilution of 22.5 percent. A USD 100 million reserve based lending facility was put in place in April 2017 and drawn upon to facilitate the share purchase offer.

During 2017, IPC assets generated significant operating cash flow of USD 138 million. This allowed IPC to pay down the credit facility put in place to fund the purchase of 25.5 million IPC common shares under the share purchase offer in the second quarter of 2017. By the end 2017, IPC was in a net cash position of USD 5.6 million, excluding the CAD 40 million (USD 32.6 million) deposit for the Suffield acquisition in Canada. Including the Canadian acquisition deposit, year-end net debt stood at USD 26.3 million.

Maximizing the value of our resource base

Good progress has been made during 2017 in adding value to IPC's resource base. IPC's 2P reserve base amounted to 29.4 MMboe as at December 31, 2016. A portfolio re-evaluation during the first half of 2017 allowed IPC to book 17.5 MMboe of best estimate contingent resources. A capital investment program was approved in the second quarter to drill two new infill wells in Malaysia on the Bertam field and acquire a 79 km^2 3D seismic survey in the Villeperdue field in France.

The two infill wells on the Bertam field in Malaysia have now been completed and commenced production in January and February of 2018 respectively.

In France, the 3D seismic acquisition on the western flank of the Villeperdue field was completed in October 2017. Work is ongoing on the seismic interpretation and we expect to be in a position by the end of 2018 to reach the concept selection milestone. In parallel, work continues on the Vert La Gravelle development plan, progressing towards a final investment decision during 2018.

As at end December 2017, IPC's 2P reserves more than quadrupled to 129.1 MMboe (including 2P reserves attributable to the Suffield acquisition in Canada). This includes a reserves replacement ratio of 76 percent for the non-Canadian assets and follows the maturation of contingent resources from the infill drilling program in Malaysia and certain upgrades in France and the Netherlands reflecting recent performance.

In addition, we are pleased to report our best estimate contingent resources as at end December 2017 have more than tripled to 63.4 MMboe (unrisked), after giving effect to the Suffield acquisition in Canada. Two additional infill locations on the Bertam field in Malaysia have been booked as well as the inclusion of the acquired resources in Canada. We are confident that we have a solid resource base in place to mature that can provide the feedstock to add to reserves in the future.

Growth from Acquisition

During the third quarter, IPC announced the transformational acquisition of the Suffield and Alderson oil and gas assets in Alberta, Canada. The Suffield and Alderson oil and gas assets are high quality conventional assets that have been operated safely and efficiently for many years. 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 transaction was completed on January 5, 2018. The consideration paid on closing, net of closing adjustments, was CAD 449 million. A further payment of CAD 12 million will be paid at 30 June 2018 in addition to certain contingent payments based oil and gas prices. The acquisition was fully funded from internally generated cash flow and existing and new lending facilities. The acquisition financing package was fully underwritten by BMO Capital Markets.

HSE Performance

Safety performance for the reporting period 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, with listing expected during the second quarter of 2018, subject to IPC fulfilling all of the requirements of the Nasdaq Stockholm.

Operations Overview

Reserves and Resources
The IPC producing assets have more than quadrupled to 129.1 MMboe of 2P reserves as at 31 December 2017 (after giving effect to the Suffield acquisition in Canada), compared to 29.4 MMboe of 2P reserves as at 31 December 2016, in each case as certified by independent third party reserves auditors. The reserves life index (RLI) as at 31 December 2017 (after giving effect to the Suffield acquisition in Canada) is approximately 11 years. Best estimate contingent resources as at 31 December 2017 more than tripled to 63.4 MMboe (unrisked), including the resources acquired in Canada and two additional infill drilling locations in the Bertam field in Malaysia.

Production
Production for the IPC assets during the fourth quarter of 2017 was in line with guidance and amounted to 9.9 Mboepd. Production of 10.3 Mboepd for the reporting period was three percent ahead of original mid-point CMD guidance. The production during the reporting period with comparatives was comprised as follows:

	Three months ended December 31		Year ended December 31	
Production [1] in Mboepd	**2017**	2016	**2017**	2016
Crude oil				
Malaysia	6.5	8.3	6.7	8.6
France	2.4	2.6	2.4	2.6
Total crude oil production	**8.9**	10.9	**9.1**	11.2
Gas				
Netherlands	1.0	1.4	1.2	1.6
Total gas production	**1.0**	1.4	**1.2**	1.6
Total production	**9.9**	12.3	**10.3**	12.8
Quantity in MMboe	**0.92**	1.14	**3.76**	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

		Three months ended December 31		Year ended December 31	
Production in Mboepd	WI	**2017**	2016	**2017**	2016
Bertam	75%	**6.5**	8.3	**6.7**	8.6

Production
Net production from the Bertam field on Block PM307 (WI 75%) during the fourth quarter was ahead of forecast at 6.5 Mboepd. Reservoir performance for the Bertam field was in line with expectation and facilities uptime for the reporting period was ahead of expectation, in excess of 99 percent.

The FPSO Bertam is required to be Malaysian flagged in order to be able to offload crude in Malaysian waters. In February 2018, an application was submitted to the Malaysian authorities for a permanent registration following a corporate restructuring transaction. The permanent flagging status for the FPSO Bertam is awaiting final regulatory approvals.

Capital Program

In December 2017, drilling commenced on the first of two sanctioned infill wells on the Bertam field, with production commencing in January 2018. The second well commenced drilling in January 2018 and was completed and put on production in February 2018. The drilling program was executed safely, on schedule and with a total gross capital cost saving of over USD 3 million relative to the original approved budget.

Organic Growth

Reprocessing of Bertam 3D seismic that was acquired in 1996 with the latest technology was completed during the fourth quarter, allowing for a full review of additional infill targets. This allowed the booking of 1.4 MMboe of additional best estimate contingent resources as at 31 December 2017.

Exploration Blocks

During the fourth quarter of 2017, the Group notified Petronas and partner Petronas Carigali of its intention to withdraw from the PM328 exploration block. Final approval of the withdrawal was pending at the end of the reporting period and was granted in February 2018.

No commitments are outstanding on any blocks in Malaysia.

CONTINENTAL EUROPE

Production in Mboepd	WI	Three months ended December 31 **2017**	Three months ended December 31 2016	Year ended December 31 **2017**	Year ended December 31 2016
France					
- Paris Basin	100% [1]	2.0	2.1	2.0	2.2
- Aquitaine	50%	0.4	0.5	0.4	0.4
Netherlands	Various	1.0	1.4	1.2	1.6
		3.4	4.0	**3.6**	4.2

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

France

Net production in France during the fourth quarter of 2017 was above forecast at 2.4 Mboepd. Production performance above expectation has been achieved across all fields in the reporting period, in particular the Villeperdue, Grandville and Les Pins fields.

Organic Growth

IPC recognizes significant development upside in the Paris Basin. In parallel with maturing the contingent resources, IPC has been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base.

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.

In respect of the Villeperdue West project, 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 3D 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 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. 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 fourth quarter of 2017 was slightly below forecast at 1.0 Mboepd due to the slippage of some planned shutdowns from the third to the fourth quarter of 2017. Overall for the year 2017, production was ahead of guidance.

Offshore, during the fourth quarter 2017, the production from the F15 field was permanently shut-in in December 2017 as planned. The facilities will be made hydrocarbon free and put on light-house mode.

Onshore, testing of the Nieuwehorne-2 exploration well was completed during the fourth quarter of 2017, and the results are currently being evaluated.

FINANCIAL REVIEW

Financial Results

Selected Financial Information

Selected consolidated statement of operations is as follows:

		Quarterly financial information					Quarterly financial information			
USD Thousands	**2017**	**Q4 2017**	Q3 2017	Q2 2017	Q1 2017	2016	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Revenue	**203,001**	**54,647**	47,926	48,496	51,932	209,880	59,592	48,498	55,568	46,222
Gross profit/(loss)	**48,758**	**13,471**	7,256	10,361	17,670	(105,639)	(114,600)	9,631	16,029	(16,699)
Net result	**22,723**	**8,977**	2,172	7,113	4,461	(95,720)	(76,097)	4,522	26,954	(51,099)
Earnings per share – USD[1]	**0.23**	**0.10**	0.02	0.07	0.04	(0.84)	(0.67)	0.04	0.24	(0.45)
Earnings per share fully diluted – USD[1]	**0.23**	**0.10**	0.02	0.07	0.04	(0.84)	(0.67)	0.04	0.24	(0.45)
Operating cash flow [2]	**138,368**	**37,156**	28,893	32,643	39,676	152,924	42,083	38,911	42,745	29,185
EBITDA [2]	**129,259**	**33,383**	26,440	30,049	39,387	150,043	41,126	38,439	43,005	27,473
Net debt [2]	**26,321**	**26,321**	47,241	35,348	(20,082)	(13,410)	(13,410)	(8,443)	(19,235)	(22,304)

[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 consolidated balance sheet information is as follows:

USD Thousands	**December 31, 2017**	December 31, 2016
Non-current assets	455,235	484,923
Current assets	134,476	87,109
Total assets	**589,711**	572,032
Total non-current liabilities	219,097	140,197
Current liabilities	63,672	26,739
Total liabilities	**282,769**	166,936
Net assets (liabilities)	**306,942**	405,096
Working capital (including cash)	**70,804**	60,370

Segment Information

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

	Three months ended – December 31, 2016				
USD Thousands	**Malaysia**	**France**	**Netherlands**	**Other [1]**	**Total**
Crude oil	40,500	9,658	–	–	50,158
NGLs	–	–	90	–	90
Gas	–	–	4,302	–	4,302
Net sales of oil and gas	40,500	9,658	4,392	–	54,550
Change in under/over lift position	–	163	125	–	288
Other operating revenue	3,805	266	463	220	4,754
Revenue	44,305	10,087	4,980	220	59,592
Production costs	(12,295)	(4,009)	(2,216)	4	(18,516)
Depletion and decommissioning costs	(14,801)	(3,677)	(1,904)	–	(20,382)
Depreciation of other assets	(7,696)	–	–	–	(7,696)
Exploration and business development costs	–	(12)	(1,339)	(284)	(1,635)
Impairment costs [2]	(125,963)	–	–	–	(125,963)
Gross profit/(loss)	(116,450)	2,389	(479)	(60)	(114,600)

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

[2] *Mainly relates to Malaysian exploration and appraisal activity expenditures.*

USD Thousands	Year ended – December 31, 2017				
	Malaysia	**France**	**Netherlands**	**Other**	**Total**
Crude oil	122,595	47,238	48	–	**169,881**
NGLs	–	–	338	–	**338**
Gas	–	–	14,963	–	**14,963**
Net sales of oil and gas	**122,595**	**47,238**	**15,349**	**–**	**185,182**
Change in under/over lift position	–	66	(679)	–	**(613)**
Other operating revenue	15,513	1,099	1,472	348	**18,432**
Revenue	**138,108**	**48,403**	**16,142**	**348**	**203,001**
Production costs	(30,393)	(26,118)	(7,926)	–	**(64,437)**
Depletion and decommissioning costs	(34,228)	(13,581)	(6,746)	–	**(54,555)**
Depreciation of other assets	(31,629)	–	–	–	**(31,629)**
Exploration and business development costs	346	(1,263)	–	(2,869)	**(3,786)**
Impairment costs	164	–	–	–	**164**
Gross profit/(loss)	**42,368**	**7,441**	**1,470**	**(2,521)**	**48,758**

USD Thousands	Year ended – December 31, 2016				
	Malaysia	**France**	**Netherlands**	**Other** [1]	**Total**
Crude oil	125,823	39,887	42	–	165,752
NGLs	–	–	447	–	447
Gas	–	–	15,248	9,269	24,517
Net sales of oil and gas	125,823	39,887	15,737	9,269	190,716
Change in under/over lift position	–	391	(174)	–	217
Other operating revenue	15,110	1,187	1,721	929	18,947
Revenue	140,933	41,465	17,284	10,198	209,880
Production costs	(27,343)	(20,507)	(9,947)	(1,358)	(59,155)
Depletion and decommissioning costs	(61,086)	(14,380)	(9,721)	–	(85,187)
Depreciation of other assets	(31,073)	–	–	–	(31,073)
Exploration and business development costs	(13,053)	(51)	(1,339)	302	(14,141)
Impairment costs [2]	(125,963)	–	–	–	(125,963)
Gross profit/(loss)	(117,585)	6,527	(3,723)	9,142	(105,639)

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

[2] *Mainly relates to Malaysian exploration and appraisal activity expenditures.*

Three months and year ended December 31, 2017 Review

Revenue
Total revenue amounted to USD 54,647 thousand for Q4 2017 compared to USD 59,592 thousand for Q4 2016 and USD 203,001 thousand for the year ended December 31, 2017 compared to USD 209,880 thousand for the year ended December 31, 2016 and is analyzed as follows:

	Three months ended December 31		Year ended December 31	
USD Thousands	**2017**	2016	**2017**	2016
Crude oil sales	46,144	50,158	169,881	165,752
Gas and NGL sales	3,768	4,392	15,301	24,964
Change in under/overlift position	(131)	288	(613)	217
Other operating revenue	4,866	4,754	18,432	18,947
Total revenue	**54,647**	59,592	**203,001**	209,880

The components of total revenue for the three months and the year ended December 31, 2017 and December 31, 2016, respectively are detailed below:

Crude oil sales

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

	Three months ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in USD thousands	40,500	9,658	–	50,158
- Quantity sold in bbls	793,937	187,745	–	981,682
- Average price realized USD per bbl	51.01	51.44	–	51.09

Crude oil sales were 8 percent lower in Q4 2017 compared to Q4 2016 attributable to 28 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 61.26/ bbl in Q4 2017 and USD 46.60/bbl in Q4 2016.

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

	Year ended – December 31, 2016			
	Malaysia	France	Netherlands	Total
Crude oil sales				
- Revenue in USD thousands	125,823	39,887	42	165,752
- Quantity sold in bbls	2,787,829	907,023	1,228	3,696,080
- Average price realized USD per bbl	45.13	43.98	33.82	44.85

Crude oil sales were 2 percent higher for the year ended December 31, 2017 compared to the year ended December 31, 2016 due to a 25 percent increase in the average sales price achieved partly offset by a 18 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 54.19/bbl for the year ended December 31, 2017 compared to USD 43.03/bbl for the comparative period. There were eleven cargoes sold in Malaysia during the year ended December 31, 2017 compared to twelve cargoes in the comparative period, primarily as a result of the lower production volumes.

Gas and NGL sales

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

	Three months ended – December 31, 2016				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in USD thousands	–	–	4,392	–	4,392
- Quantity sold in Mcf	–	–	847,211	–	847,211
- Average price realized USD per Mcf	–	–	5.18	–	5.18

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

	Year ended – December 31, 2016				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in USD thousands	–	–	15,695	9,269	24,964
- Quantity sold in Mcf	–	–	3,482,363	1,069,066	4,551,429
- Average price realized USD per Mcf	–	–	4.51	8.67	5.48

The gas sales revenue for the year ended December 31, 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 year ended December 31, 2017 are 22 percent lower than the comparative period due to the naturally declining production, but this has been offset by a 25 percent higher realized gas price.

Other operating revenue

Other operating revenue amounted to USD 4,866 thousand for Q4 2017 compared to USD 4,754 thousand for Q4 2016 and USD 18,432 thousand for the year ended December 31, 2017 compared to USD 18,947 thousand for the year ended December 31, 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 maintaining strategic inventory levels in France.

Production costs

Production costs including inventory movements amounted to USD 17,374 thousand for Q4 2017 compared to USD 18,516 thousand for Q4 2016 and USD 64,437 thousand for the year ended December 31, 2017 compared to USD 59,155 thousand for the comparative period and is analyzed as follows:

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

	Three months ended – December 31, 2016					
USD Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	19,224	5,996	2,216	(4)	(11,729)	15,703
USD/boe[2]	25.18	25.22	16.34	n/a	n/a	13.82
Change in inventory position	4,800	(1,987)	–	–	–	2,813
Production Costs	24,024	4,009	2,216	(4)	(11,729)	18,516

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

	Year ended – December 31, 2016					
USD Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	73,032	22,476	9,947	1,358	(46,664)	60,149
USD/boe[2]	23.18	23.94	17.32	7.00	n/a	12.38
Change in inventory position	975	(1,969)	–	–	–	(994)
Production costs	74,007	20,507	9,947	1,358	(46,664)	59,155

[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 11.07 and USD 8.37 for Malaysia for the year ended December 31, 2017 and 2016 respectively.

Production costs excluding inventory movements (operating costs)

Production costs excluding inventory movements (operating costs) amounted to USD 18,269 thousand for Q4 2017, compared to USD 15,703 thousand for Q4 2016 and USD 60,749 thousand for the year ended December 31, 2017 compared to USD 60,149 thousand for the year ended December 31, 2016. Included in Q4 2017 are costs of USD 1,415 thousand associated with the French fields which mainly relate to a well stimulation program and an amount USD 727 thousand of direct production taxes in connection to the French fields as a result of changes in tax legislation during Q4 2017 with a retrospective effect as of January 1, 2017. Included in the year ended December 31, 2017 are costs of USD 3,309 thousand associated with the Bertam shutdown. Included in the year ended December 31, 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 combined result in a slight increase of the costs for the year ended December 31, 2017 compared to 2016, along with reduced project and maintenance activities in the Netherlands in 2017. Besides the slight increase in the costs, the cost per boe increased for the year ended December 31, 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 was only the one lifting forecast in 2017 which was lifted in March.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 14,006 thousand for Q4 2017 compared to USD 20,382 thousand for Q4 2016 and USD 54,555 thousand for the year ended December 31, 2017 compared to USD 85,187 thousand for the comparative period. The amounts as stated for 2017 include USD 117 thousand of decommissioning cost in connection to the French assets. The depletion charge per country is analyzed in the following tables:

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

	Three months ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	14,801	3,677	1,904	20,382
Depletion USD per boe	19.39	15.47	14.03	17.93

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

	Year ended – December 31, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Depletion in USD thousands	61,086	14,380	9,721	85,187
Depletion USD per boe	19.39	15.32	16.93	17.53

The depletion amount for the Netherlands includes an accelerated depletion charge for Q4 2017 and the year ended December 31, 2017 of USD 1,668 thousand in connection to the permanent shut-in of the F15 field offshore in December 2017. Excluding the accelerated depletion charge the depletion rate per boe is USD 12.55 for Q4 2017 and USD 11.76 for the year ended December 31, 2017. The depletion rate per barrel for France was positively impacted in Q4 2017 due to a change in estimate for site restoration cost. 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 7,916 thousand for Q4 2017 compared to USD 7,696 thousand for Q4 2016 and USD 31,629 thousand for the year ended December 31, 2017 compared to USD 31,073 thousand for the comparative period. 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 1,880 thousand for Q4 2017 compared to USD 1,635 thousand for Q4 2016 and USD 3,786 thousand for the year ended December 31, 2017 compared to USD 14,141 thousand for the year ended December 31, 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 year ended December 31, 2017 mainly represent the costs of business development activities for an amount of USD 2,869 thousand and some past exploration costs in France for an amount of USD 1,263 thousand related to pre-licensing costs incurred in France, following an announcement by the French government in December 2017 that no new petroleum exploration licences will be granted. The significant exploration costs in 2016 mainly related to the unsuccessful exploration wells drilled on the SB307/308 licence in Malaysia.

Impairment costs of oil and gas properties
Impairment costs of oil and gas properties amounted to USD – for Q4 2017 compared to USD 125,963 thousand for Q4 2016 and USD 164 thousand credit for the year ended December 31, 2017 compared to USD 125,963 thousand for the comparative period. Impairment costs for the year ended December 31, 2016 related to a decision to remove the contingent resources associated with gas discoveries in the Sabah region offshore East Malaysia and the Tembakau gas discovery in PM307 offshore Peninsular Malaysia.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 4,075 thousand for Q4 2017 compared to USD 205 thousand for Q4 2016 and USD 10,400 thousand for the year ended December 31, 2017 compared to USD 1,931 thousand for the comparative period. 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 Group's corporate structure and management post Spin-Off.

Net financial items
Net financial items for Q4 2017 amounted to USD 2,191 thousand compared to USD 36,508 thousand credit for Q4 2016 and USD 14,907 thousand for the year ended December 31, 2017 compared to USD 15,385 thousand credit for the comparative period. Included in the amount for the year ended December 31, 2017 is a largely non-cash foreign exchange loss of USD 8,922 mainly resulting from 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 3,557 thousand for the year ended December 31, 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. The net financial items for the year ended December 31, 2016 mainly consisted of non-cash foreign exchange gains of USD 19,070 thousand.

Income tax
The corporate income tax credit for Q4 2017 was USD 1,772 thousand compared to a charge of USD 2,604 thousand for Q4 2016 and a corporate tax charge of USD 728 thousand for the year ended December 31, 2017 compared to USD 4,887 thousand for the comparative period. There was a current tax charge of USD 196 in the year ended December 31, 2017 compared to a USD 2,199 thousand credit in the comparative period related to a Dutch petroleum tax refund. The deferred tax charge for the year ended December 31, 2017 amounted to USD 532 thousand compared to USD 7,086 thousand for the comparative period 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 year ended December 31, 2017 was as follows:

USD Thousands	Malaysia	France	Netherlands	Total
Development	11,708	4,696	1,759	**18,163**
Exploration and evaluation	(92)	4,251	755	**4,914**
	11,616	8,947	2,514	**23,077**

The development expenditure in Malaysia mainly relates to the drilling of an infill well on the Bertam field. 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 123,051 thousand as at December 31, 2017, which included USD 121,213 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, members of the Group 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. Operating cash flows were used to repay some of the initial debt and in September 2017, USD 30.0 million was drawn to partly fund a CAD 40.0 million deposit (USD 32.6 million) in respect of the Suffield acquisition. Cash flow from the assets has been used to reduce the amount outstanding under the credit facility to USD 60.0 million as at December 31, 2017. Net debt as at December 31, 2017 is USD 26.3 million after deducting cash balances from the amount drawn under the facility. The decrease compared to the USD 47.2 million reported at September 30, 2017 is attributable to the cash flow generated from the assets.

Cash and cash equivalents held amounted to USD 33.7 million as at December 31, 2017. The Corporation held cash to meet imminent operational funding requirements in the different countries, as well as in respect of the completion of the Suffield acquisition.

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 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 December 31, 2017 of USD 23.5 million is due to Lundin Petroleum in December 2018.

In connection with the completion of the Suffield acquisition, members of the Group entered into an amendment to the existing reserve-based lending credit facility on December 20, 2017 to increase such facility from USD 100 million to USD 200 million and IPC entered into a CAD 250 million reserve-based lending credit facility and a CAD 60 million second lien facility in Canada on January 5, 2018. The amendment to the existing reserve-based lending credit facility became effective in January 2018.

Following completion of the Suffield acquisition, the Group had net debt of approximately USD 355 million. The Group's cash flows from its operations will fully fund its projected 2018 operating and capital expenditures. The Group expects to apply excess cash flows to repay a portion of its outstanding debt. The Group is in full compliance with the covenants under the credit facilities, which are customary for the size and nature of such facilities.

Working Capital

As at December 31, 2017, the Group had a net working capital balance including cash of USD 70,804 thousand compared to USD 60,370 thousand as at December 31, 2016. The main movements in working capital during the year ended December 31, 2017 is the inclusion of the deposit in relation to the Suffield acquisition of USD 31,898 thousand and USD 23,460 thousand working capital residual liability to Lundin Petroleum following the Spin- Off. The amounts are derived from the face of the balance sheet and the change in working capital differs to the amount stated in the statement of cash flow due to the inclusion of the cash balances and the non-cash foreign exchange differences arising on the revaluation of the balances held in subsidiaries with a different functional currency to the Group's presentational currency.

Non-IFRS Measures

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

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

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

"EBITDA" is calculated as net result before financial items, taxes, depletion of oil and gas properties, exploration costs, impairment costs and depreciation and adjusted for non-recurring profit/loss on sale of assets and other income.

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

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

Reconciliation of Non-IFRS Measures

Operating cash flow

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

	Three months ended December 31		Year ended December 31	
USD Thousands	**2017**	2016	**2017**	2016
Revenue	**54,647**	59,592	**203,001**	209,880
Production costs	**(17,374)**	(18,516)	**(64,437)**	(59,155)
Current tax	**(117)**	1,007	**(196)**	2,199
Operating cash flow	**37,156**	42,083	**138,368**	152,924

EBITDA

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

	Three months ended December 31		Year ended December 31	
USD Thousands	**2017**	2016	**2017**	2016
Net result	**8,977**	(76,097)	**22,723**	(95,720)
Net financial items	**2,191**	(36,508)	**14,907**	(15,385)
Income tax	**(1,772)**	2,604	**728**	4,887
Depletion	**14,006**	20,382	**54,555**	85,187
Depreciation of other assets	**7,916**	7,696	**31,629**	31,073
Exploration and business development costs	**1,880**	1,635	**3,786**	14,141
Impairment costs	–	125,963	**(164)**	125,963
Depreciation included in general, administration and depreciation expenses [1]	**185**	255	**1,095**	1,249
Other income and sale of assets (non-recurring)	**–**	(4,804)	**–**	(1,352)
EBITDA	**33,383**	41,126	**129,259**	150,043

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

Operating costs

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

	Three months ended December 31		Year ended December 31	
USD Thousands	**2017**	2016	**2017**	2016
Production costs	**17,374**	18,516	**64,437**	59,155
Change in inventory position	**895**	(2,813)	**(3,688)**	994
Operating costs	**18,269**	15,703	**60,749**	60,149

Net debt

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

USD Thousands	**December 31, 2017**	December 31, 2016
Bank loans	**60,000**	– [1]
Cash and cash equivalents	**(33,679)**	(13,410)
Net debt	**26,321**	(13,410)

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

Off-balance Sheet Arrangements

As at December 31, 2017 IPC, through its subsidiary IPC Malaysia BV, had issued bank guarantees to the customs authorities for an amount of USD 899 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 February 21, 2018.

Contractual Obligations and Commitments

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

Transactions with Related Parties

Transactions with corporate entities
As at the date of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum AB of USD 27,429 thousand which has been reduced to USD 23,460 thousand as at December 31, 2017. Instalments of this amount bear interest at 3.5% from the date of an original repayment schedule. This amount is reflected as a current liability as it is due before the end of December 2018. Expensed interest of USD 31 thousand is included in the 2017 consolidated financial statements related to this liability.

Lundin Petroleum has charged the Group USD 504 thousand in respect of office space rental and USD 2,042 thousand in respect of shared services provided since the Spin-Off date. IPC has charged Lundin Petroleum USD 461 thousand in respect of consultancy fees in 2017.

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

Remuneration of Directors and Senior Management
Remuneration of Directors and Senior Management includes all amounts earned and awarded to the Group's Board of Directors and Senior Management. Senior Management includes the Group's President and Chief Executive Officer, Chief Financial Officer, General Counsel and Corporate Secretary, Vice President of Operations, Vice President of Reservoir Development and Vice President of Corporate Planning and Investor Relations.

Directors' fees include Board and Committee fees. Management's short-term wages, bonuses and benefits include salary, benefits, bonuses and any other compensation earned or awarded in 2017 from the Spin-Off date.

USD Thousands	**2017**
Directors' fees	334
Management's short-term wages, bonuses and benefits	2,712
	3,046

At December 31, 2017, IPC share-based incentive plans remain unvested.

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at December 31, 2017, the Corporation had entered into two foreign exchange forward instruments, fully contingent on completion of the Suffield acquisition, as described below under "Currency Risk".

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

Capital Management

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

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

Price of Oil and Gas

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

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

Currency Risk

The Group'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 Group will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.

In connection with the Suffield acquisition, IPC entered into forward currency hedges to meet the future CAD financing requirements. As at December 31, 2017, IPC had the following outstanding conditional currency hedges:

Buy [1]	Sell	Contractual exchange rate [1]	Settlement period
MCAD 101.7	MUSD 80.0	CAD 1.2715: USD [1]	Dec.15,2017 – June 15,2018
MCAD 57.0	MUSD 45.0	CAD 1.2661:USD [1]	Dec.15, 2017 – June 1, 2018

[1] *The actual CAD and exchange rate depends on the date of settlement of the contracts.*

The currency hedges have been settled on 3 January 2018 for a total amount of MCAD 158.5, realizing a gain of USD 1,623 thousand which was applied to the Suffield purchase price.

Interest Rate Risk

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

Credit Risk

The Group may be exposed to third party credit risk through contractual arrangements with counterparties who buy the Group's crude products. The Group's policy is to limit credit risk by only entering into oil and gas sales agreements with reputable and creditworthy oil and gas and trading companies. Where it is determined that there is a credit risk for oil and gas sales, the Group's policy is to require credit enhancement from the purchaser. The Group's policy on joint venture parties is to rely on the provisions of the underlying joint operating agreements to take possession of the licence or the joint venture partner's share of production for non-payment of cash calls or other amounts due. In addition, cash is to be held and transacted only through major banks.

RISK AND UNCERTAINTIES

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

Non Financial Risks

Exploration, Development and Production Risks: Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Group depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. There is a risk that additional commercial quantities of oil and natural gas will not be discovered or acquired by the Group. Production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

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

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 Group's assets and may have a material adverse effect on the business, financial condition, results of operations and prospects associated with the Group's assets.

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

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 Group'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, contingent resources and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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. In 2017, the French government enacted legislation to cease granting new petroleum exploration licenses in France and to restrict the production of oil and gas under existing production licenses in France from 2040. The Group continues to work closely with other industry participants and the French authorities with respect to this legislation. IPC does not expect that this legislation will have a material adverse effect on the Group's operations or financial condition.

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 March 2018 that allows it to offload crude in Malaysian waters. In February 2018, an application was submitted to the Malaysian authorities for a permanent registration following a corporate restructuring transaction. The permanent flagging status for the FPSO Bertam is awaiting final regulatory approvals. As the FPSO provides a significant revenue stream, a failure to obtain the flagging status may result in a reduction of earnings for the Group 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 Group may make acquisitions and dispositions of businesses and assets in the ordinary course of business, including the recent 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 Group's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Group. In addition, non-core assets may be periodically disposed of, so that the Group can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Group, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Group.

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

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

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

Competition for Resources and Markets: The international petroleum industry is competitive in all its phases. The Group competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas.

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

Climate Change Legislation: The oil and natural gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Group or the Group's assets, some of which may be material. 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 Group and its operations and financial condition.

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

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

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

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

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

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

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 Group's business, financial condition, results of operations, cash flows and future prospects.

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

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

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three and twelve month periods ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

Control Framework

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

- our intention to continue to implement our strategies to build long-term shareholder value;
- the benefits of the Suffield acquisition;
- IPC's intention to review future potential growth opportunities;
- our belief that our resource base will provide feedstock to add to reserves in the future;
- the ability of our high quality portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the integration of the Suffield-related operations into IPC;
- potential future growth opportunities in North America;
- organic growth opportunities in France;
- results of infill drilling in Malaysia;
- results of 3D seismic survey in France;
- future development potential of the Suffield operations;
- the expectation that the anticipated 2018 capital expenditures will provide future development and growth opportunities in 2019 and beyond;
- status of the submission for permanent flagging status in Malaysia;
- potential acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- future production levels including 2018 production guidance;
- 2018 operating cost forecast;
- 2018 capital expenditure budget including future capital expenditures and their allocation to exploration and development activities; and
- future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:

- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- the uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- health, safety and environmental risks;
- commodity price and exchange rate fluctuations;
- interest rate fluctuations;
- marketing and transportation;
- loss of markets;
- environmental risks;
- competition;
- incorrect assessment of the value of acquisitions;
- failure to complete or realize the anticipated benefits of acquisitions or dispositions;
- the ability to access sufficient capital from internal and external sources;
- failure to obtain required regulatory and other approvals; and
- changes in legislation, including but not limited to tax laws, royalties and environmental regulations.

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

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the MCR, the MD&A (See "Cautionary Statement Regarding Forward-Looking Information" therein), the Corporation's Non-Offering Prospectus dated April 17, 2017 (See "Risk Factors" and "Forward-Looking Information" therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE DATA

This MD&A contains references to estimates of gross 2P reserves attributed to the Corporation's oil and gas assets. Gross reserves are the total working interest reserves before the deduction of any royalties and including any royalty interests receivable.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France, Malaysia and the Netherlands are effective as of December 31, 2017 and were prepared by IPC and audited by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel's January 1, 2018 price forecasts as referred to below.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada are effective as of January 5, 2018, being the completion date for the acquisition of this assets by IPC, and were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2018 price forecasts. The volumes are reported and aggregated by IPC in this MD&A as being as at December 31, 2017.

The price forecasts used in the reserve audit / evaluation are available on the website of McDaniel (www.mcdan.com), and are contained in the MCR referred to below.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 129.1 MMboe as at December 31, 2017, after giving effect to the Suffield acquisition in Canada, by the mid-point of the 2018 production guidance of 30,000 to 34,000 boepd.

"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.

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.

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

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. <u>All of the Corporation's contingent resources are classified as development unclarified.</u> Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable. Of the Corporation's 63.4 MMboe best estimate contingent resources <u>(unrisked)</u>, 17.4 MMboe are light and medium crude oil, 7.4 MMboe are heavy crude oil and 38.6 MMboe are conventional natural gas.

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

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

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

The reserves and resources information and data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the Corporation's Annual Information Form for the year ended December 31, 2017, which will be filed on SEDAR (accessible at www.sedar.com) on or before March 31, 2018. Further information with respect to IPC's 2P reserves, contingent resources and estimates of future net revenue, including assumptions relating to the calculation of net present value and other relevant information related to the contingent resources disclosed, is disclosed in the material change report (MCR) dated and filed on the date of this MD&A by IPC and available under IPC's profile on www.sedar.com and on IPC's website at www.international-petroleum.com.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD	Canadian dollar
EUR	Euro
USD	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
MMboe	Million barrels of oil equivalents
Mcf	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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