Q2

International Petroleum Corporation

Management's Discussion and Analysis

Three and six months ended June 30, 2017

International Petroleum Corp.

Management's Discussion and Analysis

Three and six months ended June 30, 2017

UNAUDITED

Contents

Non-IFRS Measures

References are made in this MD&A to Operating Cash Flow ("OCF"), Earnings Before Interest, Tax, Depreciation and Amortization ("EBITDA"), operating costs and Net Debt which are not generally accepted accounting measures under IFRS and therefore may not be comparable with definitions of OCF, EBITDA, operating costs and Net Debt that may be used by other entities. Management believes that OCF, EBITDA, operating costs and Net Debt are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 21 .

Forward-Looking Statements

Certain statements contained in this MD&A constitute forward-looking information under applicable Canadian securities laws. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "forecast", "estimate", "expect", "seek", "anticipate", "plan", "continue", "project", "predict", "intend", "objectives", "strategies", "potential", "target", "guidance", "may", "will", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. International Petroleum Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. For additional information underlying forward-looking information, refer to the "Cautionary Statement Regarding Forward-Looking Information" on page 29.

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

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

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 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 is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in this MD&A. The contingent resources referred to in this press release are further described in this MD&A, including with respect to risks and uncertainties related to the contingent resources.

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

Management's Discussion and Analysis
Three and six months ended June 30, 2017
UNAUDITED

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 August 8, 2017 and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three and six months ended June 30, 2017 ("Financial Statements").

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

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

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

Further information in respect of IPC, the Reorganization and the Spin-Off are available in the Final Prospectus. A copy of the Final Prospectus may be obtained on SEDAR at www.sedar.com under the profile of IPC.

The main business of IPC is exploring for, developing and producing oil and gas. IPC holds a portfolio of oil and gas production assets and development projects in Malaysia, France and the Netherlands with exposure to growth opportunities. IPC also acquired certain legacy non-producing interests and non-active entities as part of the Spin-Off, which are in the process of being relinquished and liquidated.

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

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

	June 30, 2017		June 30, 2016		December 31, 2016	
	Average	Period end	Average	Period end	Average	Period end
1 EUR equals USD	1.0825	1.1412	1.1155	1.1102	1.1066	1.0541
1 USD equals MYR	4.3892	4.2925	4.1028	3.9904	4.1455	4.4860

SECOND QUARTER 2017 HIGHLIGHTS

Operational Highlights

Health, Safety and Environment
- No material incidents
- No oil or chemical spills

Production
- Total average production of 10,600 barrels of oil equivalent (boe) per day (boepd) net for the second quarter of 2017 and 11,100 boepd for the first six months of 2017 (the reporting period).
- 4 percent above mid-point guidance for the second quarter of 2017 and year to date production.
- Operating costs[1] per boe below guidance at USD 14.40 for the second quarter of 2017 and USD 13.30 for the reporting period. The operating cost guidance for the full year is reduced to USD 17.20 per boe.

Projects and Capital Activities
- Reservoir studies and development of contingent resources has been a major focus in the first half of 2017, resulting in additional projects being approved.
- Best estimate contingent resources assessed by IPC at 17.5 million boe (MMboe) as at June 30, 2017.
- Capital expenditure guidance for 2017 increased to USD 38 million following the approval of a 3D seismic acquisition program in France and the drilling of two infill wells in Malaysia.
- 3D seismic in the Villeperdue field (France – Paris Basin) targeting a western extension of the main field which remains undeveloped – targeting 4.1 MMboe of best estimate contingent resources.
- Two infill wells in Malaysia which are targeting potential volumes between existing production wells within the main Bertam field structure. Capital costs are related to wells and tie-in only as facilities are already in place and require no modification. Targeting 2.3 MMboe of gross best estimate contingent resources and at breakeven oil prices of less than USD 20 per boe.
- Study work continues with the aim of maturing additional opportunities in both France and Malaysia.

Country Summary

Malaysia
- Average production in the second quarter of 2017 of 7,000 boepd net from the operated Bertam field (working interest (WI) 75%).
- In excess of 99 percent average facilities uptime on the Bertam field during the reporting period.
- Reservoir studies have identified additional infill wells which are expected to be drilled in the fourth quarter of 2017, subject to finalizing partner approval and securing rig capacity. Further work is ongoing to mature additional near field and infill opportunities through the course of 2018.
- Expected production from the infill wells are forecast to offset natural field decline rates, increasing the average IPC overall production in 2018 relative to the 2017 forecast of 9,000 to 11,000 boepd.

France
- Average production in the second quarter of 2017 of 2,100 boepd net from the operated Paris Basin fields and 400 boepd net from the non-operated Aquitaine fields.
- Villeperdue 3D seismic project approved with acquisition on track for the third quarter of 2017.
- Vert La Gravelle field development plan optimization and horizontal well design work is progressing, with a decision on the concept selection expected to be made prior to 2017 year end.

Netherlands
- Average production in the second quarter of 2017 of 1,100 boepd net from the non-operated Dutch fields.

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

Financial Highlights

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Revenue	**48,496**	55,568	**100,428**	101,790
Gross profit/(loss)	**10,361**	16,029	**28,031**	(670)
Net result	**7,113**	26,954	**11,574**	(24,145)
Operating cash flow [1]	**32,643**	42,746	**72,319**	71,930
EBITDA [1]	**30,049**	43,005	**69,436**	70,478
Net debt [1]	**35,348**	(19,235)	**35,348**	(19,235)

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

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

OPERATIONS REVIEW

Business Overview

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

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

Delivering Operational Excellence
During the second quarter of 2017, our assets have continued to deliver with production of 10,600 boepd, representing a 4 percent increase above our second quarter mid-point guidance. For the six months ended June 30, 2017, production was 11,100 boepd, 4 percent ahead of mid-point guidance.

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

The recent scheduled Bertam FPSO shutdown has been completed and production is back online. The operations team has executed a safe and successful shutdown with scope completed and the schedule met as originally planned. The pressure debottlenecking has been completed and we expect now to be able to produce certain wells that were constrained at higher rates going forward.

Financial resilience in a low oil price environment
IPC is highly free cash flow generative given the low cost nature of our assets. We are reducing our all in cash operating cost guidance for the full year from USD 18.75 per barrel to USD 17.20 per barrel, following good performance during the reporting period. During our February Capital Markets Day presentation, we guided an operating cash flow generation of USD 82 to USD 140 million (assuming a Brent oil price of USD 40 to 60 per barrel and mid-point production guidance of 10,000 boepd). For the six months ended June 30, 2017, operating cash flow generation was ahead of guidance at USD 72.3 million based upon a first half average Brent oil price of close to USD 52 per barrel.

IPC put in place a USD 100 million reserve based lending facility to facilitate the share purchase offer. The primary objective of the offer was to remove Statoil as a large non-core shareholder and a potential major overhang on the stock. Approximately 25.5 million shares were purchased for a consideration of USD 90 million and subsequently cancelled through an internal reorganization. Following the completion of this offer, our net debt level was USD 35 million by the end of the second quarter, demonstrating the robust free cash flow generation from IPC at low oil prices.

Maximizing the value of our resource base
We believe that we can add significant value to IPC's existing assets through a renewed focus on organic growth. We can report that having re-evaluated our assets in France and Malaysia that we have a best estimate contingent resource base of 15.8 MMboe and 1.7 MMboe respectively amounting to a total best estimate contingent resource base of 17.5 MMboe as at June 30, 2017. This represents an impressive 59 percent of our year end 2016 reported 2P reserve number of 29.4 MMboe.

We are also pleased to report that we are already moving forward with plans to develop these contingent resources. We have approved the drilling of two additional infill wells on the Bertam field in Malaysia during the fourth quarter of this year subject to finalising partner approval and securing rig capacity. These infill wells are expected to generate significant returns for shareholders given an essentially fixed operating cost base on the Bertam field. Drilling costs have fallen by around one-third compared to wells drilled on the Bertam field in 2014/15 and no other capital investment is required as the Bertam wellhead platform was designed to accommodate additional wells. The forecast net capital expenditure increase in 2017 will be USD 21.7 million targeting net best estimate contingent resources of 1.7 MMboe. These wells are forecast to breakeven at below USD 20 per barrel and, based on the forward oil price curve, to pay back in around eight months. From a production perspective, contribution from these infill wells is expected to enable IPC to more than offset the natural decline from our assets as we move into 2018.

In France we are optimizing the Vert La Gravelle development plan and are looking to progress past the Decision Gate 2 (DG2) concept select milestone by the end of 2017. This project was started back in 2013 by Lundin Petroleum with the drilling of two wells and installation of all the facilities, however was suspended as a result of Lundin Petroleum's capital allocation priorities. We are currently evaluating the potential to apply horizontal drilling on this project for the first time in our Paris Basin Rhaetian fields and this could have a wider application in our other fields by lifting initial well productivity.

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

Acquisition opportunities

On the acquisitions side we have been very active since our launch, reviewing a number of opportunities. We believe that we are sitting at an optimal time in the industry cycle and feel confident we can identify a transaction that fits IPC's strategy within the next six to twelve months. Our focus is on diversifying our production and cash flow base and acquiring a quality asset that we believe will grow materially in value through time. We have a broad geographical remit and are looking at assets in the production and/or development stage so that we can apply leverage using conservative bank lending parameters and thus minimize any dilution to our shareholders.

HSE Performance and 2017 Guidance

Safety performance in the first half of 2017 has been good 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.

Our full year production guidance of 9,000 to 11,000 boepd is retained and we are revising upwards our capital expenditure guidance from USD 10 million to USD 38 million following the decision to proceed with two infill wells in Malaysia in the fourth quarter and a 3D seismic survey on the Villeperdue field in France. In addition we are reducing our operating cost per barrel estimate from USD 18.75 to USD 17.20.

Swedish Listing

IPC is progressing its plans to list its shares on the Nasdaq Stockholm during the third quarter, subject to IPC fulfilling the requirements of Nasdaq Stockholm.

Operations Overview

Reserves and Resources

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

Production

Production for the IPC producing assets during second quarter of 2017 amounted to 10.6 Mboepd and was above the midpoint of the production guidance by about 4 percent. The production during the reporting period with comparatives was comprised as follows:

Production [1] in Mboepd	Three months ended Q2 2017	Three months ended Q2 2016	Six months ended Q2 2017	Six months ended Q2 2016	12 months ended 2016
Crude oil					
France	2.5	2.5	2.5	2.6	2.6
Malaysia	7.0	8.7	7.3	8.6	8.6
Total crude oil production	**9.5**	11.2	**9.8**	11.2	11.2
Gas					
Netherlands	1.1	1.6	1.3	1.6	1.6
Total gas production	**1.1**	1.6	**1.3**	1.6	1.6
Total production	**10.6**	12.8	**11.1**	12.8	12.8
Quantity in MMboe	**0.96**	1.17	**2.00**	2.33	4.66

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

SOUTH EAST ASIA

Malaysia

Production in Mboepd	WI	Three months ended Q2 2017	Three months ended Q2 2016	Six months ended Q2 2017	Six months ended Q2 2016	12 months ended 2016
Bertam	75%	**7.0**	8.7	**7.3**	8.6	8.6

Peninsular Malaysia

Production

Net production from the Bertam field on Block PM307 (WI 75%) during the reporting period was in line with forecast at 7.3 Mboepd. Reservoir performance for the Bertam field was also in line with expectation and facilities uptime for the reporting period was in excess of 99 percent, with several months completed with no production outages at all.

Capital Program
During the reporting period, work has continued on reservoir studies and identification of additional near field and low risk opportunities to grow production. A full review of possible bypassed oil within the Bertam field was completed and five infill locations identified and ranked. From this study two infill locations were high graded, sanctioned for development and drilling is planned to commence in the fourth quarter of 2017. These wells are expected to add best estimate contingent resources of 2.3 MMboe (gross). Net cash costs for these wells are around USD 22 million, with use of inventory purchased as part of the initial development phase for Bertam. The wells are of the same design and configuration as the successfully completed development wells and have no requirement for additional operating or capital expenditure on the facilities. The cost for these wells are 33 percent lower than the cost of the wells in the initial field development phase. The placement of the wells is in between existing producers, which minimizes the subsurface risks due to a known structure with well control and a history matched model with over two years of production history. Breakeven analysis shows a positive return on investment at Brent Crude prices lower than USD 20 per boe and the investment payback period is around eight months based on forward curve oil price assumptions.

A 3D seismic acquisition program was completed on the Bertam field in 1996, which was used during the development of the field and subsequent drilling activities. Reprocessing of this data set with the latest technology has been ongoing since early 2017, allowing for a full review of additional infill targets and the near field opportunity set with the aim to add low cost, low risk production into existing infrastructure. This study and analysis will continue over the remainder of 2017 and into 2018.

The contingent resource estimates reported for Malaysia relate to the drilling of two infill locations in the producing Bertam field. For further information on the Bertam field, reference is made to the Final Prospectus. The product type is light crude oil. The risk and uncertainty associated with the Malaysia contingent resources is reduced because the two proposed infill wells are close to existing wells, with the main risk relating to competitive drainage from offset wells. Recovery of the contingent resources requires the drilling of two development horizontal wells tied-back to existing infrastructure.

Exploration Blocks
Petronas, the Malaysian oil and gas regulator, has approved the relinquishment of the PM307 Block exploration area and granted to IPC a gas holding area for the Tembakau gas discovery.

An extension to the drill or drop decision on exploration Block PM328 was submitted in the first quarter to extend the decision by six months until September 2017, subject to approval from Petronas. A review of the prospective potential within this block is ongoing.

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

No commitments are outstanding on any blocks in Malaysia.

CONTINENTAL EUROPE

		Three months ended		Six months ended		12 months ended
Production in Mboepd	WI	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016	2016
France						
- Paris Basin	100% [1]	2.1	2.1	2.1	2.2	2.2
- Aquitaine	50%	0.4	0.4	0.4	0.4	0.4
Netherlands	Various	1.1	1.6	1.3	1.6	1.6
		3.6	4.1	**3.8**	4.2	4.2

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

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

Organic Growth
IPC recognizes significant development upside in the Paris Basin portfolio as evidenced by our 2C:2P ratio of 87percent. In parallel to working the contingent resources we have also been actively working on optimizing the Vert La Gravelle project which is already reflected in the 2P reserves base. Following a detailed evaluation and ranking exercise of all of these opportunities we have prioritized the Vert La Gravelle re-development optimization and the Villeperdue West opportunities.

The Vert La Gravelle field has been on production since the mid 1980s and has long been recognized as a field with waterflood and development drilling upside. A field re-development project was sanctioned in 2014 however as a result of Lundin Petroleum's capital re-allocation priorities, the project was postponed after the construction and commissioning of the facilities and the drilling of the first two wells. IPC is taking the opportunity to revisit the development concept sanctioned in 2014 in particular we are investigating the merits of applying horizontal well technology as a means to optimize value. Work completed to date is encouraging and it is expected that the Decision Gate 2 concept selection milestone will be reached by year end 2017. The unoptimized development concept is already reflected in our 2P reserves base.

Villeperdue West development is the single largest contingent resource opportunity in the IPC portfolio at 4.1 MMboe of best estimate contingent resources. The concept is to extend the development drilling to the west into an area that was considered to be water bearing when the initial field development was executed in the 1980s. Production trends on the west flank combined with our mapping and geologic assessment point towards significant bypassed oil potential which can be developed and tied into existing infrastructure. There remains structure and reservoir risk which is being addressed through the acquisition of 79 km2 of high resolution three dimensional seismic. The seismic acquisition is on track to start in early August and will continue to completion in the third quarter of 2017. Seismic processing, interpretation and subsequent reservoir development studies will continue through 2017 and into 2018 as a step towards monetizing this resource. The seismic survey will also improve the structural definition of the Villeperdue Deep prospect.

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

The Netherlands
Net production for the reporting period from the Netherlands was in line with forecast at 1.3 Mboepd, which is above CMD expectations due to better than expected field production and deferment of shutdowns. The Slootdorp wells have been producing intermittently since late March 2017 due to permitting restrictions, however the operator is working to bring the field back on full time production.

Offshore we have seen the successful installation and commissioning of the new 10" pipeline from L4 to K6. The E17-A5ST development well which was planned to be drilled in 2nd half of 2017 has been delayed to Q1 2018.

Onshore the compressor installation at the Mildam junction in the Gorredijk license is progressing as per schedule and expected to be fully operational in Q3 2017. Preparations for the Nieuwehorne-2 exploration well have been ongoing and it is expected to spud in Q3.

FINANCIAL REVIEW

Financial Results

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Revenue	**48,496**	55,568	**100,428**	101,790
Gross profit/(loss)	**10,361**	16,029	**28,031**	(670)
Net result	**7,113**	26,954	**11,574**	(24,145)
Operating cash flow [1]	**32,643**	42,746	**72,319**	71,930
EBITDA [1]	**30,049**	43,005	**69,436**	70,478
Net debt [1]	**35,348**	(19,235)	**35,348**	(19,235)

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

Summarized interim condensed consolidated balance sheet information is as follows:

US$ Thousands	**June 30, 2017**	December 31,2016
Non-current assets	462,080	484,923
Current assets	75,474	87,109
Total assets	**537,554**	572,032
Total non-current liabilities	197,115	140,197
Current liabilities	53,144	26,739
Total liabilities	**250,259**	166,936
Net assets (liabilities)	**287,295**	405,096
Working capital (including cash)	**22,330**	60,370

Segment Information

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

	Three months ended – June 30, 2017				
US$ Thousands	**Malaysia**	**France**	**Netherlands**	**Other**	**Total**
Crude oil	32,679	8,508	13	–	**41,200**
NGLs	–	–	96	–	**96**
Gas	–	–	3,183	–	**3,183**
Net sales of oil and gas	**32,679**	**8,508**	**3,292**	**–**	**44,479**
Change in under/over lift position	–	(113)	(177)	–	**(290)**
Other operating revenue	3,975	266	112	(46)	**4,307**
Revenue	**36,654**	**8,661**	**3,227**	**(46)**	**48,496**
Production costs	(9,793)	(4,405)	(1,852)	10	**(16,040)**
Depletion	(8,920)	(3,855)	(1,169)	–	**(13,944)**
Depreciation of other assets	(7,906)	–	–	–	**(7,906)**
Exploration and evaluation costs	175	(4)	–	(580)	**(409)**
Impairment costs	164	–	–	–	**164**
Gross profit/(loss)	**10,374**	**397**	**206**	**(616)**	**10,361**

	Three months ended – June 30, 2016				
US$ Thousands	**Malaysia**	**France**	**Netherlands**	**Other** [1]	**Total**
Crude oil	30,300	14,616	–	–	44,916
NGLs	–	–	118	–	118
Gas	–	–	3,483	2,074	5,557
Net sales of oil and gas	30,300	14,616	3,601	2,074	50,591
Change in under/over lift position	–	211	(81)	–	130
Other operating revenue	3,851	321	366	309	4,847
Revenue	34,151	15,148	3,886	2,383	55,568
Production costs	(2,936)	(7,919)	(2,823)	(244)	(13,922)
Depletion	(15,364)	(3,543)	(2,522)	–	(21,429)
Depreciation of other assets	(7,822)	–	–	–	(7,822)
Exploration and evaluation costs	3,651	(31)	–	14	3,634
Gross profit/(loss)	11,680	3,655	(1,459)	2,153	16,029

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

US$ Thousands	Six months ended – June 30, 2017				
	Malaysia	**France**	**Netherlands**	**Other**	**Total**
Crude oil	58,333	25,744	38	–	**84,115**
NGLs	–	–	198	–	**198**
Gas	–	–	7,767	–	**7,767**
Net sales of oil and gas	**58,333**	**25,744**	**8,003**	**–**	**92,080**
Change in under/over lift position	–	(202)	(393)	–	**(595)**
Other operating revenue	7,693	539	551	160	**8,943**
Revenue	**66,026**	**26,081**	**8,161**	**160**	**100,428**
Production costs	(10,642)	(13,794)	(3,475)	10	**(27,901)**
Depletion	(18,505)	(7,371)	(2,572)	–	**(28,448)**
Depreciation of other assets	(15,666)	–	–	–	**(15,666)**
Exploration and evaluation costs	58	(24)	–	(580)	**(546)**
Impairment costs	164	–	–	–	**164**
Gross profit/(loss)	**21,435**	**4,892**	**2,114**	**(410)**	**28,031**

US$ Thousands	Six months ended – June 30, 2016				
	Malaysia	**France**	**Netherlands**	**Other** [1]	**Total**
Crude oil	54,090	21,267	20	–	75,377
NGLs	–	–	240	–	240
Gas	–	–	7,394	9,269	16,663
Net sales of oil and gas	54,090	21,267	7,654	9,269	92,280
Change in under/over lift position	–	225	(256)	–	(31)
Other operating revenue	7,506	627	880	528	9,541
Revenue	61,596	22,119	8,278	9,797	101,790
Production costs	(11,915)	(12,289)	(5,466)	(1,344)	(31,014)
Depletion	(30,324)	(7,157)	(5,314)	–	(42,795)
Depreciation of other assets	(15,644)	–	–	–	(15,644)
Exploration and evaluation costs	(12,986)	(31)	–	10	(13,007)
Gross profit/(loss)	(9,273)	2,642	(2,502)	8,463	(670)

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

Three and six months ended June 30, 2017 Review

Revenue

Total revenue amounted to USD 48,496 thousand for Q2 2017 compared to USD 55,568 thousand for Q2 2016 and USD 100,428 thousand for the first six months of 2017 compared to USD 101,790 thousand for the first six months of 2016 and is analyzed as follows:

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Crude oil sales	41,200	44,916	84,115	75,377
Gas and NGL sales	3,279	5,675	7,965	16,903
Change in under/overlift position	(290)	130	(595)	(31)
Other operating revenue	4,307	4,847	8,943	9,541
Total revenue	**48,496**	55,568	**100,428**	101,790

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

Crude oil sales

	Three months ended – June 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	32,679	8,508	13	**41,200**
- Quantity in bbls	622,967	187,243	347	**810,557**
- Average price realized US$ per bbl	52.46	45.44	36.34	**50.83**

	Three months ended – June 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	30,300	14,616	–	44,916
- Quantity in bbls	648,689	326,474	–	975,163
- Average price realized US$ per bbl	46.71	44.77	–	46.06

Crude oil sales were 8 percent lower in Q2 2017 compared to Q2 2016 attributable to 17 percent lower sales volumes during the quarter partly offset by a 10 percent increase in the oil price realized. The volumes sold in Q2 2017 were lower primarily due a cargo lifting in France relating to the Aquitaine fields of 126,797 bbls in Q2 2016 (no lifting in Q2 2017). The realized sales price is based on Brent crude oil prices and the average market Brent crude oil price was USD 49.64/bbl in Q2 2017 and USD 45.59/bbl in Q2 2016.

	Six months ended – June 30, 2017			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	58,335	25,744	38	**84,115**
- Quantity in bbls	1,069,837	521,887	887	**1,592,611**
- Average price realized US$ per bbl	54.53	49.33	43.30	**52.82**

	Six months ended – June 30, 2016			
	Malaysia	**France**	**Netherlands**	**Total**
Crude oil sales				
- Revenue in US$ thousands	54,090	21,267	20	75,377
- Quantity in bbls	1,324,297	522,768	645	1,847,710
- Average price realized US$ per bbl	40.85	40.68	30.86	40.80

Crude oil sales were 12 percent higher for the first six months of 2017 compared to the first six months of 2016 due to a 29 percent increase in the average sales price achieved partly offset by a 14 percent decrease in the volumes sold. The realized sales price is based on Brent crude oil prices and the average market Brent crude oil price was USD 51.72/bbl in the first six months of 2017 compared to USD 39.81/bbl for the comparative period. There were five cargoes sold in Malaysia during the first six months of 2017 compared to six cargoes in the comparative period, primarily as a result of the lower production volumes.

Gas and NGL sales

	Three months ended – 30 June 2017				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in US$ thousands	–	–	3,279	–	**3,279**
- Quantity in mcf	–	–	638,801	–	**638,801**
- Average price realized US$ per mcf	–	–	5.13	–	**5.13**

	Three months ended – 30 June 2016				
	Malaysia	**France**	**Netherlands**	**Indonesia**	**Total**
Gas and NGL sales					
- Revenue in US$ thousands	–	–	3,601	2,074	5,675
- Quantity in mcf	–	–	851,816	236,852	1,088,668
- Average price realized US$ per mcf	–	–	4.23	8.76	5.21

	Six months ended – 30 June 2017				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in US$ thousands	–	–	7,965	–	**7,965**
- Quantity in mcf	–	–	1,455,883	–	**1,455,883**
- Average price realized US$ per mcf	–	–	5.47	–	**5.47**

	Six months ended – 30 June 2016				
	Malaysia	France	Netherlands	Indonesia	Total
Gas and NGL sales					
- Revenue in US$ thousands	–	–	7,634	9,269	16,903
- Quantity in mcf	–	–	1,781,969	1,069,066	2,851,035
- Average price realized US$ per mcf	–	–	4.28	8.67	5.93

The gas sales revenue for the three and six months ended June 30, 2016 includes revenue in respect of the Singa field in Indonesia. The Singa field was sold in April 2016. The average price realized for Singa gas revenue was based on a fixed contract price and is therefore higher compared to the Dutch assets where the price realized is based on market prices. Dutch gas volumes sold in the six months ended June 30, 2017 are 18 percent lower than the comparative period due to the naturally declining production, but this has been offset by a 28 percent higher realized gas price.

Other operating revenue
Other operating revenue amounted to USD 4,307 thousand for Q2 2017 compared to USD 4,847 thousand for Q2 2016 and USD 8,943 thousand for the first six months of 2017 compared to USD 9,541 thousand for the first six months of 2016. Other operating revenue mainly represents third party lease fee income received by the Group for the leasing of the owned FPSO Bertam facility to the Bertam field in Malaysia, but also includes tariff income from France and the Netherlands and income for maintain strategic inventory levels in France.

Production costs
Production costs including inventory movements amounted to USD 16,040 thousand for Q2 2017 compared to USD 13,922 thousand for Q2 2016 and USD 27,901 thousand for the first six months of 2017 compared to USD 31,014 thousand for the first six months of 2016 and is analyzed as follows:

	Three months ended – June 30, 2017					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	18,088	5,512	1,842	–	(11,603)	**13,839**
USD/boe[2]	28.45	24.33	18.39	–	n/a	**14.38**
Change in inventory position	3,308	(1,107)	–	–	–	**2,201**
Production costs	**21,396**	**4,405**	**1,842**	**–**	**(11,603)**	**16,040**

	Three months ended – June 30, 2016					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	18,238	5,938	2,805	262	(11,603)	15,640
USD/boe[2]	23.02	25.56	19.87	6.08	n/a	12.94
Change in inventory position	(3,699)	1,981	–	–	–	(1,718)
Production Costs	14,539	7,919	2,805	262	(11,603)	13,922

	Six months ended – June 30, 2017					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	35,172	11,059	3,465	–	(23,078)	**26,618**
USD/boe[2]	26.67	24.64	15.01	–	n/a	**13.32**
Change in inventory position	(1,452)	2,735	–	–	–	**1,283**
Production costs	**33,720**	**13,794**	**3,465**	**–**	**(23,078)**	**27,901**

	Six months ended – June 30, 2016					
US$ Thousands	Malaysia	France	Netherlands	Indonesia	Other [3]	Total
Operating costs[1]	37,397	11,239	5,448	1,362	(23,206)	32,240
USD/boe[2]	23.91	23.86	18.33	7.00	n/a	12.76
Change in inventory position	(2,276)	1,050	–	–	–	(1,226)
Production costs	35,121	12,289	5,448	1,362	(23,206)	31,014

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

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

[3] *Included in the Malaysia 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 production costs in Malaysia reduces the production cost per boe to USD 9.17 and USD 9.07 for Malaysia for the six months ended June 30, 2017 and 2016 respectively.*

Production costs excluding inventory movements (operating costs)

Production costs excluding inventory movements (operating costs) amounted to USD 13,839 thousand for Q2 2017, compared to USD 15,640 thousand for Q2 2016 and USD 26,618 thousand for the first six months of 2017 compared to USD 32,240 thousand for the first six months of 2016. Included in the first six months of 2016 is USD 2,267 thousand for the workover of two shut-in production wells on the Bertam field and USD 1,362 which relates to the Singa field, Indonesia, which was sold in April 2016. These items account for a significant part of the 17 percent reduction in the costs in the first six months of 2017 compared to 2016, along with reduced project and maintenance activities in the Netherlands in the first half of 2017. Despite the reduction in the costs, the cost per boe increased for the three and six months ended June 30, 2017 compared to 2016 due to the lower production volumes in 2017.

Change in inventory position

The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies 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 France, due to the relatively low level of production from the Aquitaine fields, there is only the one lifting forecast in 2017 (lifted March 2017) and so inventory levels will continue to increase throughout the remainder of the year.

Depletion

The total depletion charge amounted to USD 13,944 thousand for Q2 2017 compared to USD 21,429 thousand for Q2 2016 and USD 28,448 thousand for the first six months of 2017 compared to USD 42,795 thousand for the first six months of 2016. The depletion charge per country is analyzed in the following tables:

	Three months ended – June 30, 2017			
	Malaysia	France	Netherlands	Total
Depletion in US$ thousands	8,920	3,855	1,169	**13,944**
Depletion US$ per boe	14.03	17.01	11.67	**14.49**

	Three months ended – June 30, 2016			
	Malaysia	France	Netherlands	Total
Depletion in US$ thousands	15,364	3,543	2,522	21,429
Depletion US$ per boe	19.39	15.25	17.87	17.72

	Six months ended – June 30, 2017			
	Malaysia	France	Netherlands	Total
Depletion in US$ thousands	18,505	7,371	2,572	**28,448**
Depletion US$ per boe	14.03	16.42	11.14	**14.23**

	Six months ended – June 30, 2016			
	Malaysia	France	Netherlands	Total
Depletion in US$ thousands	30,324	7,157	5,314	42,795
Depletion US$ per boe	19.39	15.20	17.88	16.94

The depletion rates for the Bertam field, Malaysia and the Dutch gas fields have reduced significantly 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. 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 7,906 thousand for Q2 2017 compared to USD 7,822 thousand for Q2 2016 and USD 15,666 thousand for the first six months of 2017 compared to USD 15,644 thousand for the first six months of 2016. This related to the depreciation of the FPSO Bertam, which is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Exploration and evaluation costs
Total expensed exploration and evaluation costs amounted to USD 409 thousand for Q2 2017 compared to a USD 3,634 thousand credit for Q2 2016 and USD 546 thousand for the first six months of 2017 compared to USD 13,007 thousand for the first six months of 2016. The costs relate to unsuccessful exploration and evaluation costs. Exploration and evaluation costs are capitalized as they are incurred and expensed when their recoverability is determined highly uncertain (for example, an unsuccessful exploration well is drilled). Expensed costs in the first six months of 2017 mainly represent costs of looking at new ventures and business opportunities. The significant exploration costs in 2016 mainly related to the unsuccessful exploration wells drilled on the SB307/308 licence in Malaysia during the first quarter. The credit in the three months ended June 30, 2016, mainly related to the reversal of an over estimate of the cost of the unsuccessful Malaysian exploration campaign expensed in the first quarter of 2016 and the fourth quarter of 2015.

General, administrative and depreciation expenses
General, administrative and depreciation expenses amounted to USD 2,854 thousand for Q2 2017 compared to a USD 1,092 thousand credit for Q2 2016 and USD 3,780 thousand for the first six months of 2017 compared to USD 952 thousand for the first six months of 2016. Up until the Spin-Off date, the general administrative and depreciation expenses are a carve out from Lundin Petroleum's financial statements and are not representative of the general, administrative and depreciation expenses associated with the IPC Group's corporate structure and management post Spin-Off. The net credit in Q2 2016 is mainly due to an adjustment of recharges from prior periods.

Net financial items
Net financial items for Q2 2017 amounted to USD 502 thousand compared to a USD 13,664 thousand credit for Q2 2016 and USD 11,453 thousand for the first six months of 2017 compared to USD 17,013 thousand for the first six months of 2016. Included in the amount for the first six months 2017 is a largely non-cash foreign exchange loss of USD 9,255 mainly resulting on USD intra-group loan funding balances held by a subsidiary with a functional currency of Euro. Foreign exchange movements occur on the settlement of transactions denominated in foreign currencies and the revaluation of working capital and loan balances to the prevailing exchange rate at the balance sheet date where those monetary assets and liabilities are held in currencies other than the functional currencies of the Group's reporting entities. In addition, the unwinding of the discount rate on the asset retirement obligations amounted to USD 1,727 thousand for the six months of 2017. Asset retirement obligations estimates are discounted back to a present value when reflected in the balance sheet and the discounting is unwound through the income statement.

Income tax
The corporate income tax charge for Q2 2017 was a USD 108 thousand credit compared to USD 379 thousand for Q2 2016 and USD 1,224 thousand for the first six months of 2017 compared to USD 2,058 thousand for the first six months of 2016. There was a current tax charge of USD 208 in the first six months of 2017 compared to a USD 1,155 thousand credit in the comparative period mainly related to a Dutch petroleum tax refund when gas prices were lower. The deferred tax charge for the first six months of 2017 amounted to USD 1,016 thousand compared to USD 3,213 thousand for the first six months of 2016 which included a deferred tax charge relating to the Singa field, Indonesia, which was sold in April 2016.

Capital Expenditure

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

US$ Thousands	Malaysia	France	Netherlands	Other	Total
Development	1,771	1,157	1,178	–	**4,106**
Exploration and appraisal	55	1,116	109	664	**1,944**
	1,826	2,273	1,287	664	**6,050**

[1] *Evaluation costs looking at business opportunities*

Capital spend in the first six months was in line with the capital budget.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 137,654 thousand as at June 30, 2017, which included USD 136,013 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Financial Position and Liquidity

Financing

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

The credit facility was initially drawn for USD 80.0 million on May 31, 2017 to partly fund the share purchase offer made to all shareholders totaling USD 90.6 million. Cash flow generated from the assets has been used to reduce the amount drawn under the credit facility to USD 50.0 million as at June 30, 2017. Net debt as at June 30, 2017 is USD 35.3 million after deducting cash balances from the amount drawn under the facility.

Cash and cash equivalents held amounted to USD 14.7 million as at June 30, 2017. Cash balances are held to meet ongoing operational funding requirements in the different countries.

Since January 1, 2017, USD 31.4 million of cash generated by the Group had been funded to Lundin Petroleum up until the Spin-Off and is shown in the interim condensed consolidated statement of cash flow. This amount was offset against the agreed net working capital amount of USD 56.9 million owing by the Group to Lundin Petroleum as at December 31, 2016 which was comprised of trade receivables, hydrocarbon inventories, well supplies and cash, net of trade payables and accruals. Further repayments of the working capital were made during the second quarter of 2017 and the net outstanding balance as at June 30, 2017 of USD 24.4 million will be repaid to Lundin Petroleum before the end of June 2018.

Working Capital

As at June 30, 2017, the Group had a net working capital balance including cash of USD 22,330 thousand compared to USD 60,370 thousand as at December 31, 2016. The main reason for the decrease in the balance is the inclusion of the USD 24,429 thousand working capital residual liability to Lundin Petroleum which was recognized following the Spin-Off. The amounts are derived from the face of the combined carve-out balance sheet and the change in working capital differs to the amount stated in the combined carve-out statement of cash flow due to the inclusion of the cash balances and the non-cash foreign exchange differences arising on the revaluation of the balances held in subsidiaries with a different functional currency to the Group's presentational currency.

Non-IFRS Measures

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

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

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

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

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

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

Reconciliation of Non-IFRS Measures

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

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Revenue	**48,496**	55,568	**100,428**	101,790
Production costs	**(16,040)**	(13,922)	**(27,901)**	(31,014)
Current tax	**188**	1,101	**(208)**	1,155
Operating cash flow	**32,644**	42,746	**72,319**	71,930

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

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Net result	**7,113**	26,954	**11,574**	(24,145)
Income tax	**(108)**	379	**1,224**	2,058
Depletion	**13,944**	21,429	**28,448**	42,795
Depreciation of other assets	**7,906**	7,822	**15,666**	15,644
Exploration costs	**410**	(3,634)	**546**	13,007
Impairment costs	**(164)**	–	**(164)**	–
Depreciation included in general, administration and depreciation expenses [1]	**447**	267	**688**	654
Sale of assets (non-recurring)	**–**	3,452	**–**	3,452
Net financial items	**502**	(13,664)	**11,453**	17,013
EBITDA	**30,049**	43,005	**69,434**	70,479

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

Operating costs
The following table sets out how operating costs is calculated:

	Three months ended		Six months ended	
US$ Thousands	**Q2 2017**	Q2 2016	**Q2 2017**	Q2 2016
Production costs	**16,040**	13,922	**27,901**	31,014
Change in inventory position[1]	**2,201**	(1,718)	**1,283**	(1,226)
Operating costs	**13,839**	15,640	**26,618**	32,240

[1] *Item is not shown in the interim condensed consolidated financial statements. See production costs section of this MD&A*

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

US$ Thousands	**June 30, 2017**	December 31,2016
Bank loans	**50,000**	–[1]
Cash and cash equivalents	**14,652**	13,410
Net debt	**35,348**	(13,410)

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

Off-balance Sheet Arrangements

There were no off-balance sheet arrangements as at June 30, 2017.

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.

International Petroleum BV, a wholly-owned subsidiary of IPC, holds 117,485,389 class A preferred shares of IPC.

Contractual Obligations and Commitments

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

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

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

As at the date of the Spin-Off, the Corporation had a residual liability for working capital owed to Lundin Petroleum AB of USD 27,429 thousand which has been reduced to USD 24,429 thousand as at June 30, 2017. This amount is reflected as a current liability as it will be paid before June 2018.

In addition, Lundin Petroleum has charged the Corporation USD 136 thousand in respect of office space rental since the Spin-Off date. IPC has charged Lundin Petroleum USD 176 thousand in respect of consultancy fees in 2017. The Corporation has also accrued an amount for shared services provided by Lundin Petroleum since the Spin-Off.

Financial Risk Management

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

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

Capital Management

The Corporation's objectives when managing capital are to safeguard the Corporation's ability to continue as a going concern and to meet its committed work program requirements in order to create shareholder value. The Corporation may put in place new credit facilities, repay debt, or pursue other such restructuring activities as appropriate. Management of the Corporation will continuously monitor and manage the Corporation's capital, liquidity and net debt position in order to assess the requirement for changes to the capital structure to meet the objectives and to maintain flexibility.

Price of Oil and Gas

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

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

Currency Risk

The Corporation's policy on currency rate hedging is, in the case of currency exposure, to consider fixing the rate of exchange for known costs in non-US dollar currencies to US dollar in advance so that future US dollar costs can be forecast with a reasonable degree of certainty. The Corporation will take into account the currency exposure, current rates of exchange and market expectations in comparison to historic trends and volatility in making the decision to hedge.

Interest Rate Risk

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

Credit Risk

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

RISK AND UNCERTAINTIES

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

Non Financial Risks

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

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

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

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

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

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

Regulatory Approvals and Compliance and Changes in Legislation and the Regulatory Environment: Oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to exploration and production activities, price, taxes, royalties and the exportation of oil and natural gas.

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

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

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

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

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

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

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

Climate Change Legislation: The oil and natural gas industry is subject to environmental regulation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Corporation or the Corporation's assets, some of which may be material. .Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

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

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

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

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

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

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

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

Financial Risks

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

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

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

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

As a result of the Corporation's initial public filing a non-offering long form prospectus offering on April 17, 2017, the Corporation is a reporting issuer in Canada from that date. As such, June 30, 2017 is the last reporting period that the Corporation is not required to and is not certifying as to the design and operating effectiveness of disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"). Comments with respect to DC&P and ICFR are based on management's observations of the Corporation's control environment and not on a complete assessment of DC&P and ICFR.

Disclosure Controls and Procedures
Management, under the supervision of the Chief Executive Officer and the Chief Financial Officer, is responsible for the design of the Company's disclosure controls and procedures in order 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.

Internal Controls over Financial Reporting
Management is also responsible for the design of the Corporation's internal controls over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. There have been no material changes to DC&P and ICFR during the periods ended June 30, 2017.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In particular and without limitation, this MD&A contains forward-looking statements pertaining to the following:
- IPC's intentions with respect to and ability to execute its growth strategies;
- forecasted operating costs of IPC for 2017;
- 2017 guidance with respect to organic and inorganic growth opportunities;
- the performance characteristics of the IPC asset base;
- IPC's oil and natural gas production levels and the overall composition of such production in 2017;
- expected 2017 activities of IPC;
- drilling plans;
- IPC's future financial capacity; and
- liquidation and relinquishment of legacy non-producing interests and non-active entities.

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

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

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

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD	Canadian dollar
EUR	Euro
USD or US$	US dollar

Oil related terms and measurements

bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Mbbl	Thousand barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMbo	Thousand cubic feet
NGL	Natural gas liquid

[1] All volume references to boe are calculated on the basis of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) unless otherwise indicated. This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

DIRECTORS

Lukas H. Lundin
Director, Chairman
Geneva, Switzerland

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

Chris Bruijnzeels
Director
Geneva, Switzerland

C. Ashley Heppenstall
Lead Director
Hong Kong

Donald Charter
Director
Toronto, Ontario

Torstein Sanness
Director
Oslo, Norway

OFFICERS

Christophe Nerguararian
Chief Financial Officer
Geneva, Switzerland

Jeffrey Fountain
General Counsel and Corporate Secretary
Geneva, Switzerland

INVESTOR RELATIONS

Rebecca Gordon
VP Corporate Planning and Investor Relations
Geneva, Switzerland

Sophia Shane
Vancouver, British Columbia
Canada

CORPORATE OFFICE

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

OPERATIONS OFFICE

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

REGISTERED AND RECORDS OFFICE

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

INDEPENDENT AUDITORS

PricewaterhouseCoopers AG
Geneva, Switzerland

TRANSFER AGENT

Computershare Trust Company of Canada
Toronto, Ontario

MEDIA RELATIONS

Robert Eriksson
Stockholm, Sweden

STOCK EXCHANGE LISTINGS

Toronto Stock Exchange and
NASDAQ First North Exchange
Trading Symbol: IPCO

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

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