Q1

International Petroleum Corporation

Management's Discussion and Analysis

Three months ended March 31, 2019

International Petroleum Corp.

Contents

Non-IFRS Measures
References are made in this MD&A to "operating cash flow" (OCF), "Earnings Before Interest, Tax, Depreciation and Amortization" (EBITDA), "operating costs" and "net debt"/"net cash" which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of OCF, EBITDA, operating costs and net debt/net cash that may be used by other public companies. Management believes that OCF, EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Corporation. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in this MD&A. See "Non-IFRS Measures" on page 18.

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 24.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in the Suffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using McDaniel's January 1, 2019 price forecasts.

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

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2018, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2019 price forecasts.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated May 8, 2019, and is intended to provide an overview of the Group's operations, financial performance and current and future business opportunities. This MD&A should be read in conjunction with IPC's unaudited interim condensed consolidated financial statements and accompanying notes for the three months ended March 31, 2019 ("Financial Statements").

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

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

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

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

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

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

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

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

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

	March 31, 2019		March 31, 2018		December 31, 2018	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1356	1.1235	1.2294	1.2321	1.1815	1.1450
1 USD equals CAD	1.3295	1.3351	1.2644	1.2893	1.2958	1.3629
1 USD equals MYR	4.0905	4.0799	3.9239	3.8680	4.0354	4.1325

FIRST QUARTER 2019 HIGHLIGHTS

Operational Highlights

- Average net production of 44,400 barrels of oil equivalent (boe) per day (boepd) for Q1 2019.
- The impact of extreme weather on Canada gas production (9% below mid-point guidance) was more than offset by higher realized gas prices (31% above forecast). All other producing assets were in line with mid-point guidance.
- Operating costs[1] per boe of USD 13.2 for Q1 2019, in line with guidance.
- Canada Suffield area oil drilling program results in line with pre-drill expectations.
- Malaysia exploration and three well infill drilling program on track to commence in Q2 2019.
- France Vert La Gravelle redevelopment project on track to commence in Q2 2019.
- Completed acquisition of lands adjoining the Blackrod project in Canada, with best estimate contingent resources (unrisked) of 243 million boe (MMboe).
- Capital expenditure budget increased from USD 166 million to USD 188 million, including to fund the enhanced oil recovery (EOR) development project at the Suffield N2N oil field and further conventional oil drilling in the acquired BlackPearl assets in Alberta.

[1] *See definition on page 18 under "Non-IFRS measures"*

Financial Highlights

	Three months ended March 31	
USD Thousands	2019	2018
Revenue	147,420	115,162
Gross profit	46,885	37,573
Net result	33,142	26,313
Operating cash flow [1]	83,056	76,060
EBITDA [1]	81,675	65,291
Net Debt [1]	256,962	309,184

[1] *See definition on page 18 under "Non-IFRS measures"*

- Strong first quarter operating cash flow generation of USD 83 million at the upper end of guidance following the inclusion of the acquired BlackPearl assets and stronger than forecast realized crude oil and natural gas prices.
- Net debt reduced from USD 309 million as at March 31, 2018 to USD 257 million as at March 31, 2019, including the debt from the BlackPearl Acquisition.

OPERATIONS REVIEW

Business Overview

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

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

With a strong set of first quarter results including for the first time the results of our BlackPearl Acquisition completed in December 2018, as well as announcing an expanded organic growth program and a very low cost acquisition of material contingent resources, we continue to make excellent progress on all fronts in delivering on that strategy.

Delivering Operational Excellence
During Q1 2019, our assets delivered average daily net production of 44,400 boepd. All assets performed in line with our mid-point guidance with the exception of Suffield gas production in Canada. Abnormally cold temperatures experienced during Q1 2019 resulted in 9% lower gas production or 1,000 boepd below the mid-point guidance as a result of freeze-offs. However, the lower production was more than offset by a much higher realized gas price of CAD 3.9 per Mcf, 31% above our forecast gas price. Production guidance for the full year is retained at 46,000 to 50,000 boepd.

Production from the Suffield Assets in Canada of almost 22,750 boepd during Q1 2019 was 5% below mid-point guidance as a result of the above mentioned cold weather. Onion Lake Thermal oil and other conventional oil production were in line with mid-point guidance at 12,600 boepd.

In Malaysia, a world class uptime performance on the Bertam FPSO in excess of 99% continued during Q1 2019. First quarter production on the Bertam field was 6,600 bopd, in line with guidance.

Production in France was in line with guidance during Q1 2019. IPC has been informed by Total that operations at their Grandpuits refinery have been temporarily suspended. Total continues to work toward resuming operations at the Grandpuits refinery, however, in parallel we are progressing alternative temporary export solutions should the suspension be prolonged to minimize the risk of any production curtailment. Currently, there is no impact on our production.

Our operating costs per boe for Q1 2019 was USD 13.2, in line with guidance.

Demonstrating Financial Resilience
IPC has continued to deliver a robust financial performance during Q1 2019 generating a record high quarterly operating cash flow of USD 83 million, at the upper end of guidance. This allowed IPC to fund its expenditure program and reduce net debt from USD 277 million at the end of 2018 to USD 257 million by the end of the first quarter.

The strong operating cash flow and free cash flow generation is the result of good operational delivery combined with stronger realized oil and gas prices relative to forecast. In particular, WTI-WCS differentials improved from USD 39 per barrel in the fourth quarter of 2018 to USD 12 per barrel in Q1 2019, driven in large part by the announced production curtailment policy in Alberta in early December 2018. As IPC's oil production in Alberta is below the 10,000 bopd threshold for curtailment, we have been able to enjoy the benefits of improved differentials without the negative impact of curtailment. In addition, the abnormally cold weather during the first quarter drove realized gas prices to more than 30% above our forecast levels.

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

2P net asset value per share increased by 37% in 2018 from USD 9.1 per share to USD 12.4 per share.

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

Progress on the 2019 work program

In Malaysia, following positive results from the 2016 and 2018 infill drilling programs and continued good reservoir performance, we approved a third phase of infill drilling on the Bertam field for execution in 2019. Three drilling locations have been approved and work continues to identify a fourth location. In addition, we plan to drill the Keruing prospect as part of the same 2019 campaign. The "West Telesto" rig mobilised this month and we remain on track for the drilling program to commence in Q2 2019. The program will entail the drilling of two infill landing pilots followed by the Keruing exploration well and the drilling of three infill wells, with the production uplift expected in the second half of 2019. Optionality exists to add further drilling at the back end of the program.

In Canada, we plan to drill seventeen development oil wells on the Suffield Asset in 2019, excluding wells related to the Suffield N2N EOR project. The drilling campaign commenced in Q4 2018 and production has been in line with pre-drill expectations. Onion Lake facility optimization and ramp up is ongoing although the abnormally cold weather during Q1 2019 has led to a slightly slower ramp up than planned as we entered the second quarter, as a result of reduced water intake for steam generation. We still expect to increase production to between 12,000 to 14,000 bopd by the end of 2019. On the gas side, the gas optimization program continues with the objective of minimizing natural declines through 2019.

In France, our team is focused on the execution of the Vert La Gravelle redevelopment project using horizontal drilling techniques. The rig has been contracted and is expected to be on location this month to commence the drilling of three wells as scheduled. In parallel we continue to mature the Villeperdue West project to a development decision later in the year.

Additional organic growth investment in 2019

We are pleased to announce that we have successfully completed our reviews of the Suffield N2N EOR development project in Canada in addition to identifying two potential new conventional oil plays on properties acquired as part of the BlackPearl transaction. The Suffield N2N EOR project is planned to involve the drilling of eight development wells and the injection of Alkaline Surfactant Polymer (ASP) to improve sweep efficiency and recovery factors. On the acquired BlackPearl properties, we plan to drill five wells, testing two potential new plays, that in the success case, could identify up to 130 conventional oil drilling locations. As a result, we are increasing our capital budget by USD 22 million, from USD 166 million which was at the upper end of our guidance to USD 188 million. The land acquisition at the Blackrod project described below is also included in this capital budget increase.

Following these changes to our capital expenditure budget, and given our very strong cash flow generation year to date, we still expect to fully fund the revised 2019 capital program from internally generated operating cash flow assuming a Brent oil price of USD 60 per barrel, Canadian WTI-WCS oil price differentials of USD 20 per barrel and gas prices in Canada of CAD 2.5 per Mcf gas price for the rest of the year, which we believe is a fairly conservative outlook relative to current strip pricing. As most of the new activities are not expected to contribute production materially in 2019, we are retaining our full-year 2019 production guidance.

Growth from Acquisition

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

We are also pleased to report that, in less than five months since completion of the BlackPearl acquisition, we have been able to acquire a significant land and contingent resource position adjacent to the Blackrod property. We believe that the acquired land position holds among the best quality reservoir and pay thickness that we currently hold in the area, significantly expanding our core area at Blackrod. These acquired lands are 100% working interest to IPC and include best estimate contingent resources (unrisked) of 243 MMboe, increasing IPC's total contingent resources at the Blackrod project to 987 MMboe and IPC's total contingent resources base to almost 1,100 MMboe.

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

HSE Performance

Health, Safety & Environmental performance (HSE) remains a priority for all operational assets. Our objective is to reduce risk and eliminate hazards to prevent the occurrence of accidents, ill health and environmental damage, as these are essential to the success of our operations. During Q1 2019, IPC recorded one low severity lost time incident in Canada.

Operations Overview

Reserves and Resources

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

IPC remains focused on organic growth and is maturing opportunities across all our operated assets. In Canada, oil drilling activities that had commenced in Q4 2018, continued into Q1 2019, complemented by gas optimization activities that continue to generate excellent production performance, halting the historical production decline. In Malaysia, we are on track to deliver a third phase of infill well drilling at the Bertam field with the drilling program expected to start during Q2 2019. In France, the Vert La Gravelle redevelopment work continued in Q1 2019 with drilling operations expected to start as planned in Q2 2019.

Production

The average net production for the IPC assets during Q1 2019 was around 1,000 boepd below the mid-point CMD guidance at 44.4 Mboepd. The extremely cold weather in Canada caused production freeze-offs and hence lower production from the Suffield Gas asset. The full year production forecast remains on track with original CMD guidance. Gas pricing during Q1 2019 was significantly higher than originally forecast leading to a net benefit for IPC. Integration of the former BlackPearl assets has delivered a significant increase in production volumes for IPC relative to 2018 levels. The production during the reporting period with comparatives was comprised as follows:

Production in Mboepd	Three months ended March 31		Year ended December 31
	2019	2018	2018
Crude oil			
Canada – Suffield	6.5	6.4	6.3
Canada – Onion Lake Thermal	9.9	–	–
Canada – Other	2.8	–	–
Malaysia	6.4	7.8	7.3
France	2.4	2.4	2.5
Total crude oil production	28.0	16.6	16.1
Gas			
Canada – Suffield	16.3	15.4	17.6
Canada – Other	0.1	–	–
Netherlands [1]	–	0.9	0.7
Total gas production	16.4	16.3	18.3
Total production	44.4	32.9	34.4
Quantity in MMboe	3.99	2.96	12.56

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

CANADA

Production in Mboepd	WI	Three months ended March 31 2019	2018	Year ended December 31 2018
- Oil Suffield	100%	6.5	6.4	6.3
- Oil Onion Lake Thermal	100%	9.9	–	–
- Oil Other	50 - 100%	2.8	–	–
- Gas	99.7%[1]	16.4	15.4	17.6
Canada		35.6	21.8	23.9

[1] *On a well count basis.*

Production
Net production from the Canadian assets during Q1 2019 was slightly below mid case CMD guidance at 35.6 Mboepd.

Organic Growth and Capital Projects
In Canada, a significant program of drilling and gas optimization opportunities have been identified by IPC as part of the operational and capital budgets for 2019.

Regulatory approvals are in place to support continued drilling through the course of 2019 in Suffield Oil. In addition to the five wells brought online at the end of 2018, a further three wells were brought online in Q1 2019 and initial rates are in line with expectations. Given the exceptional results from the 2018 Suffield Gas optimization program, an extensive program has been identified and sanctioned in 2019. Swabbing work has continued and the first 25 recompletions were executed in Q1 2019. Optimization activity levels are anticipated to ramp up as weather and surface conditions improve. At Onion Lake Thermal, the planned facility debottlenecking and sustaining capital preparation work continued.

Having successfully completed project reviews as well as delivering a strong financial performance, we are planning to move forward with the Suffield N2N EOR development project and additional drilling on conventional oil properties acquired in the BlackPearl Acquisition in Alberta.

MALAYSIA

Production in Mboepd	WI	Three months ended March 31 2019	2018	Year ended December 31 2018
Bertam	75%	6.4	7.8	7.3

Production
Net production from the Bertam field on Block PM307 during Q1 2019 was in line with expectation at 6.4 Mboepd. Exceptional operational performance continued in Q1 2019 with facility uptime at almost 100%.

Organic Growth
Following positive results from the 2016 and 2018 infill drilling programs and continued good reservoir performance, IPC has planned and budgeted a third phase of infill drilling on the Bertam field for execution in 2019. Three firm infill well locations are planned with a fourth opportunity undergoing review. Drilling contracts have been signed, the rig is currently mobilizing and site preparations have been completed with the drilling program due to commence during Q2 2019.

EUROPE

Production in Mboepd	WI	Three months ended March 31 2019	Three months ended March 31 2018	Year ended December 31 2018
France				
- Paris Basin	100% [1]	1.9	2.0	2.0
- Aquitaine	50%	0.5	0.4	0.5
Netherlands [2]	Various	–	0.9	0.7
		2.4	3.3	3.2

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

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

Production

Net production in France during Q1 2019 was in line with expectation at 2.4 Mboepd. Production from the Paris Basin is transported by pipeline to the Grandpuits refinery, owned and operated by Total.

During Q1 2019, IPC was advised by Total that operations at the Grandpuits refinery have been temporarily suspended. This suspension did not have any effect on IPC's Paris Basin production or sales during the first quarter of 2019. IPC continues to coordinate with Total regarding the resumption of operations at the Grandpuits refinery and at the same time, IPC is reviewing alternative transportation and sale options for Paris Basin production.

Organic Growth

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

The first phase of the Vert La Gravelle redevelopment is scheduled for execution in 2019. Preparatory works commenced late in Q4 2018 and continued in Q1 2019, with an anticipated first well spud in Q2 2019.

Processing and interpretation of the Villeperdue West 3D seismic data was completed in Q4 2018 with the aim of reaching a final development investment decision in Q3 2019.

FINANCIAL REVIEW

Financial Results

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

Selected Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Revenue	147,420	111,898	106,746	120,637	115,162	54,647	47,926	48,496
Gross profit	46,885	26,311	37,060	45,920	37,573	13,471	7,256	10,361
Net result	33,142	29,346	26,487	21,498	26,313	8,977	2,172	7,113
Earnings per share – USD	0.20	0.29	0.30	0.24	0.30	0.10	0.02	0.07
Earnings per share fully diluted – USD	0.20	0.29	0.29	0.23	0.30	0.10	0.02	0.07
Operating cash flow [1]	83,056	58,322	67,949	76,687	76,060	37,156	28,893	32,643
EBITDA [1]	81,675	58,032	66,240	74,478	65,291	33,383	26,440	30,049
Net debt at period end [1, 2]	256,962	276,761	213,217	254,628	309,184	26,321	47,241	35,348

[1] *See definition on page 18 under "Non-IFRS measures".*

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	March 31, 2019	December 31, 2018
Non-current assets	1,194,470	1,184,184
Current assets	110,406	98,899
Total assets	1,304,876	1,283,083
Total non-current liabilities	477,112	490,981
Current liabilities	97,271	96,315
Total liabilities	574,383	587,296
Net assets	730,493	695,787
Working capital (including cash)	13,135	2,584

Segment Information

The Group operates within several geographical areas. Operating segments are reported at a country level, with Canada being further analyzed by main areas: (i) Suffield Assets, (ii) Onion Lake Thermal and (iii) other Canadian assets. This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

USD Thousands	Three months ended – March 31, 2019						
	Canada – Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Other	Total
Crude oil	32,145	33,000	8,069	36,412	11,713	–	121,339
NGLs	85	–	–	–	–	–	85
Gas	23,856	–	95	–	–	–	23,951
Net sales of oil and gas	**56,086**	**33,000**	**8,164**	**36,412**	**11,713**	**–**	**145,375**
Change in under/over lift position	–	–	–	–	3,270	–	3,270
Royalties	(1,191)	(3,403)	(1,326)	–	–	–	(5,920)
Hedging settlement	–	499	–	–	–	–	499
Other operating revenue	–	–	–	3,825	286	85	4,196
Revenue	**54,895**	**30,096**	**6,838**	**40,237**	**15,269**	**85**	**147,420**
Production costs	(28,733)	(11,491)	(5,380)	(10,049)	(7,120)	–	(62,773)
Depletion	(11,333)	(6,233)	(810)	(8,274)	(3,211)	–	(29,861)
Depreciation of other assets	–	–	–	(7,789)	–	–	(7,789)
Exploration and business development costs	–	–	(30)	–	–	(82)	(112)
Gross profit	**14,829**	**12,372**	**618**	**14,125**	**4,938**	**3**	**46,885**

USD Thousands	Three months ended – March 31, 2018					
	Canada - Suffield	Malaysia	France	Netherlands[1]	Other	Total
Crude oil	27,014	43,686	20,550	23	–	91,273
NGLs	84	–	–	119	–	203
Gas	17,201	–	–	3,401	–	20,602
Net sales of oil and gas	44,299	43,686	20,550	3,543	–	112,078
Change in under/over lift position	–	–	(41)	12	–	(29)
Royalties	(1,706)	–	–	–	–	(1,706)
Other operating revenue	208	3,825	278	387	121	4,819
Revenue	42,801	47,511	20,787	3,942	121	115,162
Production costs	(28,514)	(5,340)	(10,713)	(1,731)	–	(46,298)
Depletion	(10,025)	(9,089)	(3,292)	(756)	–	(23,162)
Depreciation of other assets	–	(7,960)	–	–	–	(7,960)
Exploration and business development costs	–	(165)	–	–	(4)	(169)
Gross profit	4,262	24,957	6,782	1,455	117	37,573

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

Three months ended March 31, 2019 Review

Revenue
Total revenue amounted to USD 147,420 thousand for Q1 2019 compared to USD 115,162 thousand for Q1 2018 and is analyzed as follows:

	Three months ended March 31	
USD Thousands	2019	2018
Crude oil sales	121,339	91,273
Gas and NGL sales	24,036	20,805
Change in under/overlift position	3,270	(29)
Royalties	(5,920)	(1,706)
Hedging settlement	499	–
Other operating revenue	4,196	4,819
Total revenue	**147,420**	115,162

The components of total revenue for Q1 2019 and Q1 2018 are detailed below:

Crude oil sales

	Three months ended – March 31, 2019					
	Canada - Suffield	Canada - Thermal	Canada - Other	Malaysia	France	Total
Crude oil sales						
- Revenue in USD thousands	32,145	33,000	8,069	36,412	11,713	**121,339**
- Quantity sold in bbls	701,086	887,128	215,800	537,695	181,610	**2,523,319**
- Average price realized USD per bbl	45.85	37.20	37.39	67.72	64.50	**48.09**

	Three months ended – March 31, 2018				
	Canada - Suffield	Malaysia	France	Netherlands[1]	Total
Crude oil sales					
- Revenue in USD thousands	27,014	43,686	20,550	23	91,273
- Quantity sold in bbls	673,153	619,244	310,971	392	1,603,760
- Average price realized USD per bbl	40.13	70.55	66.08	58.38	56.91

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

Crude oil revenue was 33% higher for Q1 2019 compared to Q1 2018 mainly due to the contribution of the former BlackPearl assets in Canada.

The Suffield Assets crude oil in Canada is blended with purchased condensate diluent volumes to meet pipeline specifications. As a result of the blended volumes, actual sales volumes are higher than produced volumes for Canada. The Canadian realized sales price is based on the Western Canadian Select ("WCS") price which trades at a discount to West Texas Intermediate ("WTI"). For Q1 2019, WTI averaged USD 55 per bbl compared to USD 63 per bbl for Q1 2018 and the average discount to WCS used in our pricing formula was USD 12 per bbl compared to USD 24 per bbl for Q1 2018. The discount from WTI to WCS significantly narrowed to average USD 12 per bbl for Q1 2019 compared to an average of USD 39 per bbl in Q4 2018.

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

All sales and expenses from the Blackrod asset SAGD pilot evaluation are being recorded as an adjustment to the capitalized costs of the project until commercial production commences. The Blackrod asset sales volume and revenue for Q1 2019 of 37,599 bbls and USD 1,144 thousand are therefore not included in the crude oil sales table above.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average Dated Brent crude oil price was USD 63 per bbl for Q1 2019 compared to USD 67 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – March 31, 2019		
	Canada - Suffield	Canada - Other	Total
Gas and NGL sales			
- Revenue in USD thousands	23,941	95	**24,036**
- Quantity sold in Mcf	8,553,764	52,321	**8,606,085**
- Average price realized USD per Mcf	2.80	1.82	**2.79**

	Three months ended – March 31, 2018		
	Canada - Suffield	Netherlands[1]	Total
Gas and NGL sales			
- Revenue in USD thousands	17,285	3,520	20,805
- Quantity sold in Mcf	8,076,660	490,130	8,566,790
- Average price realized USD per Mcf	2.14	7.18	2.43

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

Gas and NGL sales revenue was 16% higher for Q1 2019 compared to Q1 2018 mainly due to the higher production volumes of the Suffield Assets following gas optimization projects carried out since acquiring the assets and a higher achieved gas price. Approximately 98% of the Suffield gas production was sold on the Alberta/Saskatchewan border at Empress with the remainder being delivered in Alberta based on AECO pricing. For Q1 2019, IPC realized an average price of CAD 3.86 per Mcf which was CAD 1.24 per Mcf above AECO average pricing and CAD 0.81 per Mcf above Empress average pricing. The increased realized price over market prices is due to forward sales that were entered into.

Hedging settlement
IPC enters into risk management contracts in order to ensure a certain level of cashflow and to comply with covenants of its financing facilities. It focuses mainly on oil price swap and collars to limit pricing exposure. IPC uses natural gas at the Onion Lake Thermal project and the Blackrod SAGD pilot project to generate steam and manages the pricing risk by entering into fixed price swaps. The oil and gas pricing contracts are not entered into for speculative purposes. Also see the Financial Risk Management section below.

The realized hedging settlement for Q1 2019 amounted to USD 499 thousand and consisted of a gain of USD 611 thousand on the gas contracts and a loss of USD 112 thousand on the oil contracts.

Other operating revenue
Other operating revenue amounted to USD 4,196 thousand for Q1 2019 compared to USD 4,819 thousand for Q1 2018 and consists of lease fee income, tariff income and fees for strategic storage of inventory in France. The significant part of other operating revenue is third party lease fee income received by the Group for the leasing of the owned FPSO Bertam to the Bertam field in Malaysia. The reduction in other operating revenue in Q1 2019 compared to Q1 2018 is mainly due to the reduction in tariff income following the sale of the gas assets in the Netherlands in December 2018.

Production costs

Production costs including inventory movements amounted to USD 62,773 thousand for Q1 2019 compared to USD 46,298 thousand for Q1 2018 and is analyzed as follows:

	Three months ended – March 31, 2019						
USD Thousands	Canada - Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Other[3]	Total
Operating costs[1]	23,232	11,491	5,380	17,541	6,647	(11,475)	52,816
USD/boe[2]	11.35	12.95	20.53	30.23	30.54	n/a	13.22
Cost of blending[4]	5,672	–	–	–	–	–	5,672
Change in inventory position	(171)	–	–	3,983	473	–	4,285
Production costs	28,733	11,491	5,380	21,524	7,120	(11,475)	62,773

	Three months ended – March 31, 2018					
USD Thousands	Canada - Suffield	Malaysia	France	Netherlands[5]	Other[3]	Total
Operating costs[1]	21,894	16,948	7,677	1,731	(11,475)	36,775
USD/boe[2]	11.15	24.13	35.66	21.02	n/a	12.40
Cost of blending[4]	6,907	–	–	–	–	6,907
Change in inventory position	(287)	(133)	3,036	–	–	2,616
Production costs	28,514	16,815	10,713	1,731	(11,475)	46,298

[1] *See definition on page 18 under "Non-IFRS measures".*

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

[3] *Included in the Malaysia operating costs is the lease cost for the FPSO Bertam which is owned by the Group. Other represents the FPSO Bertam lease fee self-to-self payment elimination. Netting the self-to-self elimination against the operating costs in Malaysia reduces the operating cost per boe for Malaysia to USD 10.45 and USD 7.79 for Q1 2019 and Q1 2018 respectively.*

[4] *Cost of blending represents the contracted purchase of diluent used for blending net of proceeds from the sale of surplus diluent. A cost of USD 407 thousand and USD 632 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q1 2019 and Q1 2018 respectively.*

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

Operating costs

Operating costs amounted to USD 52,816 thousand for Q1 2019 compared to USD 36,775 thousand for Q1 2018. The increase in operating costs is mainly due to the contribution of the former BlackPearl assets in Canada and is in line with forecast. Operating costs per boe amounted to USD 13.22 per boe in Q1 2019 compared with USD 12.40 per boe in Q1 2018 and is in line with CMD guidance of USD 13.30 per boe for Q1 2019.

Cost of blending

For the Suffield Assets in Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. The cost of the diluent net of proceeds from the sale of surplus diluent amounted to USD 5,672 thousand for Q1 2019 compared to USD 6,907 thousand for Q1 2018. As a result of the blending, actual sales volumes are higher than produced barrels. A cost of USD 407 thousand and USD 632 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q1 2019 and Q1 2018 respectively.

Change in inventory position

The Bertam field in Malaysia is located offshore and production is lifted and sold from the FPSO Bertam when a cargo parcel size is reached. Accordingly, the timing of a lifting varies based on the inventory level on the FPSO facility and the change in inventory position varies, both positively and negatively, from period to period. Inventories are valued at the lower of cost including depletion and market value and the difference in the valuation between period ends is reflected in the change in inventory position in the statement of operations. In the Aquitaine Basin, France, there was no cargo lifting in Q1 2019 compared to a cargo lifting in Q1 2018.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 29,861 thousand for Q1 2019 compared to USD 23,162 thousand for Q1 2018, with the inclusion of a USD 7,043 thousand depletion charge for Q1 2019 relating to the former BlackPearl assets. The depletion charge is analyzed in the following tables:

	Three months ended – March 31, 2019					
	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Depletion cost in USD thousands	11,333	6,233	810	8,274	3,211	29,861
USD per boe	5.54	7.03	3.09	14.26	14.75	7.48

	Three months ended – March 31, 2018				
	Canada - Suffield	Malaysia	France	Netherlands[1]	Total
Depletion in USD thousands	10,025	9,089	3,292	756	23,162
USD per boe	5.10	12.94	15.30	9.18	7.81

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

The depletion charge is derived by applying the depletion rate per boe to the volumes produced in the period by each field.

Depreciation of other assets

The total depreciation of other assets amounted to USD 7,789 thousand for Q1 2019, compared to USD 7,960 thousand for Q1 2018. This related to the depreciation of the FPSO Bertam, which is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 3,311 thousand for Q1 2019, compared to USD 3,734 thousand for Q1 2018.

Net financial items

Net financial items amounted to USD 4,067 thousand for Q1 2019, compared to USD 9,153 thousand for Q1 2018 and included a largely non-cash net foreign exchange gain of USD 3,899 thousand for Q1 2019 compared to a net foreign exchange loss of USD 1,419 thousand in Q1 2018. The foreign exchange movements mainly result from the revaluation of external loan balances and intra-group loan funding balances. Excluding foreign exchange movements, the net financial items amounted to USD 7,966 thousand for Q1 2019, compared to USD 7,734 thousand for Q1 2018. The interest expense for Q1 2019 amounted to USD 4,294 thousand compared to USD 4,434 thousand for Q1 2018 and included interest expense of USD 1,834 for Q1 2019 relating to the acquired BlackPearl financing facilities. The unwinding of the asset retirement obligation discount rate amounted to USD 2,666 thousand for Q1 2019 compared to USD 2,388 thousand for Q1 2018 and the increase is due to the inclusion of the BlackPearl asset retirement obligation at the year end partly offset by the removal of the unwinding expense following the sale of the assets in the Netherlands in December 2018.

Income tax

The corporate income tax charge amounted to USD 6,365 thousand for Q1 2019, compared to a credit of USD 1,627 thousand for Q1 2018. There was a current tax credit of USD 7,196 thousand in Q1 2018 largely related to a non-recurring Dutch petroleum tax refund relating to historical intragroup charges and an industry change in the calculation of the present value of the asset retirement obligation.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in Q1 2019 was as follows:

USD Thousands	Canada – Suffield	Canada – Thermal	Canada – Other	Malaysia	France	Total
Development	9,359	6,393	353	465	2,743	**19,313**
Exploration and evaluation	–	–	1,075	1,449	49	**2,573**
	9,359	6,393	1,428	1,914	2,792	**21,886**

Capital expenditure of USD 21,886 thousand is slightly under the forecast for Q1 2019 and was mainly spent on drilling on the Suffield Assets, Onion Lake Thermal facilities and preparations for the drilling campaign in Malaysia and the Vert La Gravelle redevelopment in France.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 83,938 thousand as at March 31, 2019, which included USD 80,486 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

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

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

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

Acquisition-related costs of approximately USD 2.3 million have been recognized in the income statement for the year ended December 31, 2018. No material acquisition-related costs were recognized in Q1 2019.

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

Financial Position and Liquidity

Financing

In connection with the April 2017 spin-off of IPC, the Group entered into a USD 100 million reserve-based lending credit facility, which was used to fund the offer to purchase common shares of IPC. The credit facility was initially drawn for USD 80 million in May 2017.

In connection with the completion of the Suffield acquisition, the Group entered into an amendment to the reserve-based lending credit facility in December 2017 to increase such facility from USD 100 million to USD 200 million and to extend the maturity to end June 2022. Concurrently, IPC Alberta Ltd entered into a CAD 250 million reserve-based lending credit facility and a CAD 60 million second lien facility in Canada on January 5, 2018.

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

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

In December 2018, in connection with the completion of the BlackPearl Acquisition, the Group assumed the debt of BlackPearl consisting of a reserve-based lending credit facility of CAD 120 million (CAD 87.5 million outstanding as at March 31, 2019) and senior secured notes outstanding of CAD 75 million. The reserve-based lending facility matures in May 2021 and the senior secured notes mature in June 2020.

The borrowing base availability under the Group's reserve-based lending credit facility is currently USD 166 million of which USD 44 million was outstanding as at March 31, 2019. The borrowing base availability of IPC Alberta Ltd.'s reserve-based lending credit facility is currently CAD 200 million of which CAD 133.8 million was outstanding as at March 31, 2019, with a maturity date of January 2021.

Total net debt as at March 31, 2019, amounted to USD 256.9 million.

The Group expects to fully fund the proposed 2019 capital program from operating cash flow assuming a Brent oil price of USD 60 per barrel, Canadian WTI-WCS oil price differentials of USD 20 per barrel and gas prices in Canada of CAD 2.5 per Mcf gas price for the rest of the year. The Group's free cash flows going forward, after operations related costs and capital expenditure, are planned to continue to be used to repay outstanding debt under the credit facilities. The Group is in full compliance with the covenants under the credit facilities, which are customary for the size and nature of such facilities.

Cash and cash equivalents held amounted to USD 8,967 thousand as at March 31, 2019. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

In connection with the Spin-Off, effective January 1, 2017, IPC owed working capital in favor of Lundin Petroleum. USD 33.5 million of the working capital adjustment including interest was paid back to Lundin Petroleum in 2017 and a further amount of USD 10 million was paid in December 2018. The final settlement of USD 14 million plus interest is due before June 30, 2019.

Working Capital

As at March 31, 2019, the Group had a net working capital balance including cash of USD 13,135 thousand compared to USD 2,584 thousand as at December 31, 2018. The main movement in working capital during the quarter results from increased trade receivables partially offset by lower derivative instrument valuations as a result of the higher oil and gas prices at the end of the quarter. The amounts are derived from the balance sheet and the change in working capital differs to the amount stated in the statement of cash flow due to the inclusion of the cash balances and the non-cash foreign exchange differences arising on the revaluation of the balances held in subsidiaries with a different functional currency to the Group's presentational currency.

Non-IFRS Measures

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

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

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

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

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

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

Reconciliation of Non-IFRS Measures

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

	Three months ended March 31	
USD Thousands	2019	2018
Revenue	147,420	115,162
Production costs	(62,773)	(46,298)
Current tax	(1,591)	7,196
Operating cash flow	83,056	76,060

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 March 31	
USD Thousands	2019	2018
Net result	33,142	26,313
Net financial items	4,067	9,153
Income tax	6,365	(1,627)
Depletion	29,861	23,162
Depreciation of other assets	7,789	7,960
Exploration and business development costs	112	169
Depreciation included in general, administration and depreciation expenses [1]	339	161
EBITDA	**81,675**	65,291

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

Operating costs

The following table sets out how operating costs is calculated:

	Three months ended March 31	
USD Thousands	2019	2018
Production costs	62,773	46,298
Cost of blending[1]	(5,672)	(6,907)
Change in inventory position	(4,285)	(2,616)
Operating costs	**52,816**	36,775

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

Net debt

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

USD Thousands	March 31, 2019	December 31, 2018
Bank loans	209,754	232,357
Senior secured notes	56,175	55,030
Cash and cash equivalents	(8,967)	(10,626)
Net debt	**256,962**	276,761

Off-Balance Sheet Arrangements

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

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

Outstanding Share Data

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

In connection with the completion of the BlackPearl Acquisition, IPC issued a total of 75,798,219 common shares to the former shareholders of BlackPearl. As at May 8, 2019, IPC has a total of 163,720,065 common shares issued and outstanding with no par value.

Nemesia S.à.r.l., Lorito Holdings S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 37,903,757 common shares in IPC.

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

IPC has 1,815,000 stock options, 791,014 IPC transitional PSP and RSP awards granted in connection with the Spin-off, and 1,032,570 IPC Performance and Restricted Share Plan awards (704,089 awards granted in July 2018 and 328,481 awards granted in March 2019), outstanding as at May 8, 2019.

Contractual Obligations and Commitments

As part of the acquisition of the Suffield Assets, the Group is required to pay Cenovus Energy Inc. additional cash consideration dependent upon the future prices of oil and natural gas for each month between January 2018 and December 2019. The potential undiscounted amount of all future payments that the Group could be required to pay as at March 31, 2019, is up to CAD 13 million (USD 10 million). A total estimated contingent consideration of CAD 10,371 thousand (USD 8,354 thousand) as at March 31, 2019, has been reflected in the Financial Statements. Of this amount, the contingent consideration paid in 2018 and Q1 2019 amounted to CAD 4,111 thousand (USD 3,079 thousand) for oil and CAD 2,003 thousand (USD 1,500 thousand) for gas.

IPC has an obligation to make payments towards historic costs on Block PM307 in Malaysia payable on the Bertam field for every 1 MMboe gross that the field produces above 10 MMboe gross. The estimated liability based on current 2P reserves has been provided for in the Group's Balance Sheet – see Note 17 Provisions of the Financial Statements.

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

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

Critical Accounting Policies and Estimates

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

Transactions with Related Parties

As a result of the Spin-Off, the Group had a residual liability for working capital owed to Lundin Petroleum of USD 14,127 thousand including accrued interest as at March 31, 2019. Instalments relating to the working capital amount bear interest at 3.5% from the date of the original repayment schedule. The amount is reflected as a current liability as it is due before the end of June 2019. Expensed interest of USD 119 thousand is included in Q1 2019 related to this liability.

Lundin Petroleum has charged the Group USD 178 thousand in respect of office space rental and USD 444 thousand in respect of shared services provided during Q1 2019.

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

Financial Risk Management

As an international oil and gas exploration and production company, IPC is exposed to financial risks such as interest rate risk, currency risk, credit risk, liquidity risks as well as the risk related to the fluctuation in the oil price. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas price, interest rate or foreign exchange hedges as the case may be. Financial instruments will be solely used for the purpose of managing risks in the business. As at March 31, 2019, the Corporation had entered into oil and gas price hedges – see below.

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

Capital Management

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

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

Price of Oil and Gas

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

Based on analysis of the circumstances, the management assesses the benefits of forward hedging monthly sales contracts for the purpose of protecting cash flow. If management believes that a hedging contract will appropriately help manage cash flow then it may choose to enter into a commodity price hedge. IPC is required to hedge a certain portion of the oil production from the assets acquired in the BlackPearl Acquisition, under the terms of the CAD 75 million senior secured notes.

The Group had gas price hedges outstanding as at March 31, 2019 which are summarized as follows:

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

The Group had oil price hedges outstanding as at March 31, 2019 which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Weighted Average Floor (WTI in USD)	Weighted Average CAP (WTI in USD)	Other
Oil Sale				
April 1, 2019 – June 30, 2019	5,200	47.26	66.20	–
April 1, 2019 – June 30, 2019	2,000	–	–	WCS CAD 54/bbl
April 1, 2019 – June 30, 2019	3,000	–	–	WTI - USD 12/bbl
July 1, 2019 – September 30, 2019	7,500	50.00	72.88	–
October 1, 2019 – December 31, 2019	3,000	49.45	68.15	–
January 1, 2020 - March 31, 2020	3,500	50.00	77.50	–
April 1, 2020 – June 30, 2020	6,150	35.00	71.74	–

All of the above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income.

These hedges had a fair value net liability of USD 4,444 thousand at March 31, 2019.

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

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

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

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

RISK AND UNCERTAINTIES

IPC is engaged in the exploration, development and production of oil and gas and is exposed to various operational, environmental, market and financial risks and uncertainties. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2018 available on SEDAR at www.sedar.com or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resource Advisory" in this MD&A.

DISCLOSURE CONTROLS AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

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

Internal Controls over Financial Reporting

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

There have been no material changes to the Groups internal control over financial reporting during the three month periods ended March 31, 2019, that have materially affected, or are reasonably likely to materially affect, the Group's internal control over financial reporting.

Control Framework

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

Acquisition of BlackPearl

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

Summary financial information related to BlackPearl is presented in the Note 9 of the Financial Statements.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

- our intention and ability to continue to implement our strategies to build long-term shareholder value;
- our intention to review future potential growth opportunities;
- the ability of our portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the continued facility uptime and reservoir performance in our areas of operation;
- the proposed Vert La Gravelle development project, including drilling, and other organic growth opportunities in France, including the Villeperdue West project;
- the status of the suspension of operations at the Grandpuits refinery, and the related effects on production and sales, in France;
- the proposed third phase of infill drilling in Malaysia and the ability to mature additional locations, and the production uplift from such drilling;
- the drilling of the Keruing prospect in Malaysia and the development options if drilling is successful;
- future development potential of the Suffield operations, including continued and future oil drilling and gas optimization programs and the N2N EOR development project;
- the proposed further conventional oil drilling in Canada, including the ability of such drilling to identify further drilling or development opportunities;
- development of the Blackrod project, including the land position acquired in May 2019, in Canada;
- the results of the facility optimization program and the work to debottleneck the facilities and injection capability, as well as water intake issues, at Onion Lake Thermal;
- the ability to integrate the assets and operations acquired in the BlackPearl Acquisition, including the ability to accelerate value creation and extend IPC's reserves life following such acquisition;
- 2019 production range, exit rate, operating costs and capital expenditure estimates;
- potential further acquisition opportunities;
- estimates of reserves;
- estimates of contingent resources;
- estimates of prospective resources;
- the ability to generate cash flows and use that cash to repay debt and to continue to deleverage; and
- future drilling and other exploration and development activities.

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

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

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

These include, but are not limited to:

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

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

Additional information on these and other factors that could affect IPC, or its operations or financial results, are included in the Financial Statements, the Corporation's Annual Information Form (AIF) for the year ended December 31, 2018 (See "Cautionary Statement Regarding Forward-Looking Information", "Reserves and Resources Advisory" and "Risk Factors") and other reports on file with applicable securities regulatory authorities, including previous financial reports, management's discussion and analysis and material change reports, which may be accessed through the SEDAR website (www.sedar.com) or IPC's website (www.international-petroleum.com).

RESERVES AND RESOURCE ADVISORY

This MD&A contains references to estimates of gross and net reserves and resources attributed to the Corporation's oil and gas assets. Gross reserves / resources are the working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests. Net reserves / resources are the working interest (operating or non-operating) share after deduction of royalty obligations, plus royalty interests in reserves/resources, and in respect of PSCs in Malaysia, adjusted for cost and profit oil. Unless otherwise indicated, reserves / resource volumes are presented on a gross basis.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in the Suffield area of Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using McDaniel's January 1, 2019 price forecasts.

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

Reserve estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in France and Malaysia are effective as of December 31, 2018, and are included in the report prepared by ERC Equipoise Ltd. (ERCE), an independent qualified reserves auditor, in accordance with NI 51-101 and the COGE Handbook, and using McDaniel's January 1, 2019 price forecasts.

The contingent resource estimates in respect of the oil and gas assets acquired in May 2019 in the Blackrod area of Canada are effective as of December 31, 2018, and have been evaluated by Sproule, in accordance with NI 51-101 and the COGE Handbook. The lands acquired will be part of the planned SAGD development at Blackrod and have the same classification (Development on Hold) as the other Blackrod lands. The same chance of development risk (77%) has been applied to the acquired lands as was used for Phase 2 and Phase 3 of the Blackrod project. These lands will be incorporated into the Phase 2 and Phase 3 development plan going forward. Additional details regarding the planned development at Blackrod, including an assessment of the contingencies, timing and economics for the proposed development, are available in the AIF.

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

The reserve life index (RLI) is calculated by dividing the 2P reserves of 288 MMboe as at December 31, 2018, by the mid-point of the initial 2019 production guidance of 46,000 to 50,000 boepd. The reserves replacement ratio is based on 2P reserves of 129.1 MMboe as at December 31, 2017 (including the 2P reserves attributable to the acquisition of the

Suffield area assets which completed on January 5, 2018), production during 2018 of 12.4 MMboe, additions to 2P reserves during 2018 of 12.7 MMboe and 2P reserves of 128.0 MMboe as at December 31, 2018 (excluding the 2P reserves attributable to the BlackPearl Acquisition which completed on December 14, 2018).

Light, medium and heavy crude oil reserves/resources disclosed in this MD&A include solution gas and other by-products.

"2P reserves" means proved plus probable reserves. "Proved reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. "Possible reserves" are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Each of the reserves categories reported (proved and probable) may be divided into developed and undeveloped categories. "Developed reserves" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing. "Developed producing reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty. "Developed non-producing reserves" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown. "Undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on a project maturity and/or characterized by their economic status.

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

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation's contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

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

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

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

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

References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves". References to "prospective resources" do not constitute, and should be distinguished from, references to "contingent resources" and "reserves".

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

OTHER SUPPLEMENTARY INFORMATION

Abbreviations

CAD or CA$	Canadian dollar
EUR or €	Euro
USD or US$	US dollar
MYR	Malaysian Ringgit
FPSO	Floating Production Storage and Offloading (facility)

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
°API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe[1]	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bscf	Billion standard cubic feet
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced Oil Recovery
Mbbl	Thousand barrels
MMbbl	Million barrels
Mboe	Thousand barrels of oil equivalents
Mboepd	Thousand barrels of oil equivalents per day
Mbopd	Thousand barrels of oil per day
MMboe	Million barrels of oil equivalents
Mcf	Thousand cubic feet
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage (a thermal recovery process)
WTI	West Texas Intermediate (a light oil reference price)
WCS	Western Canadian Select (a heavy oil reference price)

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

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