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International Petroleum Corporation

Interim Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2020

International Petroleum Corp.

Interim Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2020 and 2019
UNAUDITED

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Interim Condensed Consolidated Statement of Operations

For the three and six months ended June 30, 2020 and 2019

UNAUDITED

USD Thousands	Note	Three months ended June 30 2020	Three months ended June 30 2019	Six months ended June 30 2020	Six months ended June 30 2019
Revenue	*2*	**44,929**	129,357	**125,465**	276,777
Cost of sales					
Production costs	*3*	(30,075)	(52,396)	(89,216)	(115,169)
Depletion and decommissioning costs		(23,298)	(29,697)	(53,572)	(59,558)
Depreciation of other assets	*10*	(2,989)	(7,789)	(6,024)	(15,578)
Exploration and business development costs		(5,104)	(188)	(5,626)	(300)
Gross profit / (loss)	*2*	**(16,537)**	39,287	**(28,973)**	86,172
General, administration and depreciation expenses		(3,095)	(2,714)	(5,905)	(6,025)
Profit / (loss) before financial items		**(19,632)**	36,573	**(34,878)**	80,147
Finance income	*4*	12,378	5,107	68	9,060
Finance costs	*5*	(5,967)	(11,271)	(22,819)	(19,291)
Net financial items		**6,411**	(6,164)	**(22,751)**	(10,231)
Profit / (loss) before tax		**(13,221)**	30,409	**(57,629)**	69,916
Income tax	*6*	11,749	(4,665)	16,088	(11,030)
Net result		**(1,472)**	25,744	**(41,541)**	58,886
Net result attributable to:					
Shareholders of the Parent Company		(1,471)	25,743	(41,530)	58,880
Non-controlling interest		(1)	1	(11)	6
		(1,472)	25,744	**(41,541)**	58,886
Earnings per share – USD[1]	*16*	**(0.01)**	0.16	**(0.26)**	0.36
Earnings per share fully diluted – USD[1]	*16*	**(0.01)**	0.15	**(0.26)**	0.35

[1] Based on net result attributable to shareholders of the Parent Company.

See accompanying notes to the interim condensed consolidated financial statements.

Interim Condensed Consolidated Statement of Comprehensive Income

For the three and six months ended June 30, 2020 and 2019

UNAUDITED

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Net result	**(1,472)**	25,744	**(41,541)**	58,886
Other comprehensive income / (loss):				
Items that may be reclassified to profit or loss, net of tax:				
Hedging gains / (losses) reclassified to profit or loss	3,448	(2,879)	6,301	(2,380)
Cash flow hedges gain / (loss)	(11,657)	5,819	(6,996)	1,532
Currency translation adjustments	12,114	7,286	(20,631)	11,529
Total comprehensive income / (loss)	**2,433**	35,970	**(62,867)**	69,567
Total comprehensive income/ (loss) attributable to:				
Shareholders of the Parent Company	2,432	35,967	(62,855)	69,562
Non-controlling interest	1	3	(12)	5
	2,433	35,970	**(62,867)**	69,567

See accompanying notes to the interim condensed consolidated financial statements.

Interim Condensed Consolidated Balance Sheet

As at June 30, 2020 and December 31, 2019

UNAUDITED

USD Thousands	Note	June 30, 2020	December 31, 2019
ASSETS			
Non-current assets			
Exploration and evaluation assets	7	18,385	27,614
Property, plant and equipment, net	8	1,096,167	1,077,881
Other tangible fixed assets, net	10	62,608	69,015
Right-of-use assets		2,211	2,700
Deferred tax assets	6	83,107	57,523
Other assets	11	18,989	17,867
Total non-current assets		1,281,467	1,252,600
Current assets			
Inventories	12	19,965	17,220
Trade and other receivables	13	42,271	77,834
Derivative instruments	20	1,595	420
Current tax receivables	6	1,008	996
Cash and cash equivalents	14	11,018	15,571
Total current assets		75,857	112,041
TOTAL ASSETS		1,357,324	1,364,641
LIABILITIES			
Non-current liabilities			
Financial liabilities	17	319,761	244,732
Lease liabilities		1,414	1,906
Provisions	18	185,529	179,997
Deferred tax liabilities	6	42,673	47,565
Total non-current liabilities		549,377	474,200
Current liabilities			
Trade and other payables	19	54,525	85,826
Financial liabilities	17	29,207	–
Current tax liabilities		220	2,706
Lease liabilities		841	844
Provisions	18	8,105	9,840
Derivative instruments	20	2,565	416
Total current liabilities		95,463	99,632
EQUITY			
Shareholders' equity		712,289	790,602
Non-controlling interest		195	207
Net shareholders' equity		712,484	790,809
TOTAL EQUITY AND LIABILITIES		1,357,324	1,364,641

Approved by the Board of Directors

(Signed) C. Ashley Heppenstall
Director

(Signed) Mike Nicholson
Director

See accompanying notes to the interim condensed consolidated financial statements.

Interim Condensed Consolidated Statement of Cash Flow

For the three and six months ended June 30, 2020 and 2019

UNAUDITED

USD Thousands	Three months ended June 30 2020	Three months ended June 30 2019	Six months ended June 30 2020	Six months ended June 30 2019
Cash flow from operating activities				
Net result	(1,472)	25,744	(41,541)	58,886
Adjustments for non-cash related items:				
Depletion, depreciation and amortization	26,714	37,839	60,448	75,829
Exploration costs	5,185	15	5,185	45
Current tax	112	465	26	2,056
Deferred tax	(11,861)	4,200	(16,114)	8,974
Capitalized financing fees	374	556	759	1,160
Foreign currency exchange	(12,365)	(4,960)	9,492	(8,859)
Interest expense	2,563	7,277	6,350	11,571
Unwinding of asset retirement obligation discount	2,646	2,651	5,289	5,317
Share-based costs	1,595	960	2,144	2,069
Other	964	47	1,139	189
Cash flow generated from operations (before working capital adjustments and income taxes)	***14,455***	*74,794*	***33,177***	*157,237*
Changes in working capital	(29,246)	17,147	(1,614)	(13,013)
Decommissioning costs paid	(2,002)	(3,301)	(2,727)	(4,125)
Other payments	–	(605)	(615)	(1,219)
Income taxes paid	(1,961)	(3,831)	(2,367)	(3,750)
Interest paid	(2,706)	(7,129)	(6,350)	(11,225)
Net cash flow from operating activities	**(21,460)**	77,075	**19,504**	123,905
Cash flow used in investing activities				
Investment in oil and gas properties	(6,422)	(39,556)	(62,612)	(61,442)
Investment in other fixed assets	(122)	(261)	(137)	(404)
Acquisition of the Suffield Assets	–	(566)	–	(744)
Acquisition of Granite (see Note 9)	–	–	(27,709)	–
Net cash (outflow) from investing activities	**(6,544)**	(40,383)	**(90,458)**	(62,590)
Cash flow from financing activities				
Borrowings / (repayments)	11,744	(21,461)	86,432	(47,496)
Paid financing fees	(1,908)	(451)	(1,908)	(451)
Purchase of own shares	–	–	(17,602)	–
Lease payment	(225)	(213)	(458)	(425)
Cash funded from / (to) Lundin Petroleum	–	(14,243)	–	(14,243)
Other payments	–	(29)	–	(29)
Net cash (outflow) from financing activities	**9,611**	(36,397)	**66,464**	(62,644)
Change in cash and cash equivalents	**(18,393)**	295	**(4,490)**	(1,329)
Cash and cash equivalents at the beginning of the period	29,368	8,967	15,571	10,626
Currency exchange difference in cash and cash equivalents	43	(36)	(63)	(71)
Cash and cash equivalents at the end of the period	**11,018**	9,226	**11,018**	9,226

See accompanying notes to the interim condensed consolidated financial statements.

Interim Condensed Consolidated Statement of Changes in Equity

For the six months ended June 30, 2020 and 2019

UNAUDITED

USD Thousands	Share capital and premium	Retained earnings	CTA	IFRS 2 reserve	MTM reserve	Total	Non-controlling interest	Total equity
Balance at January 1, 2019	567,116	129,697	(6,495)	4,958	296	695,572	215	695,787
Pension liability adjustment[1]	–	(3,223)	–	–	–	(3,223)	–	(3,223)
Net result	–	58,880	–	–	–	58,880	6	58,886
Acquisition of BlackPearl[2]	–	–	–	–	9,013	9,013	–	9,013
Cash flow hedge	–	–	–	–	(9,861)	(9,861)	–	(9,861)
Currency translation difference	–	–	11,213	120	197	11,530	(1)	11,529
Total comprehensive income	–	58,880	11,213	120	(651)	69,562	5	69,567
Dividend distribution	–	–	–	–	–	–	(29)	(29)
Share based payments	–	–	–	1,813	–	1,813	–	1,813
Balance at June 30, 2019	567,116	185,354	4,718	6,891	(355)	763,724	191	763,915

[1] For comparative purposes, the pension liability was restated in Q1 2019.

[2] The acquisition of BlackPearl Resources Inc. ("BlackPearl") was completed in December 2018 and the preliminary purchase price allocation was recognized in December 2018. A further adjustment was recognized in Q1 2019.

USD Thousands	Share capital and premium	Retained earnings	CTA	IFRS 2 reserve	MTM reserve	Pension reserve	Total	Non-controlling interest	Total equity
Balance at January 1, 2020	549,311	230,038	6,052	6,249	3	(1,051)	790,602	207	790,809
Net result	–	(41,530)	–	–	–	–	(41,530)	(11)	(41,541)
Acquisition of Granite[1]	–	–	–	–	1,311	–	1,311	–	1,311
Cash flow hedge	–	–	–	–	(2,006)	–	(2,006)	–	(2,006)
Currency translation difference	–	–	(20,209)	(398)	(23)	–	(20,630)	(1)	(20,631)
Total comprehensive income / (loss)	–	(41,530)	(20,209)	(398)	(718)	–	(62,855)	(12)	(62,867)
Purchase of own shares	(17,602)	–	–	–	–	–	(17,602)	–	(17,602)
Share based payments	–	–	–	2,144	–	–	2,144	–	2,144
Balance at June 30, 2020	531,709	188,508	(14,157)	7,995	(715)	(1,051)	712,289	195	712,484

[1] See Note 9

See accompanying notes to the interim condensed consolidated financial statements.

Notes to the Interim Condensed Consolidated Financial Statements

For the three and six months ended June 30, 2020 and 2019
UNAUDITED

1. CORPORATE INFORMATION

A. The Group

The Corporation is incorporated and domiciled in British Columbia, Canada under the Business Corporations Act. The address of its registered office is Suite 2600, 595 Burrard Street, P.O. Box 49314, Vancouver, BC V7X 1L3, Canada and its business address is Suite 2000, 885 West Georgia Street, Vancouver, BC V6C 3E8, Canada.

On March 5, 2020, IPC completed the acquisition of all of the issued and outstanding shares of Granite Oil Corp. ("Granite") by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Granite Acquisition").

B. Basis of preparation

The unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting using accounting policies consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The financial statements should be read in conjunction with IPC's annual consolidated financial statements for the year ended December 31, 2019, which have been prepared in accordance with IFRS as issued by the IASB.

The unaudited interim condensed consolidated financial statements are presented in United States Dollars (USD), which is the Group's presentation and functional currency. The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis, except for items that are required to be accounted for at fair value as detailed in the Group's accounting policies. Intercompany transactions and balances have been eliminated.

The unaudited interim condensed consolidated financial statements have been approved by the Board of Directors of IPC and authorized for issuance on August 4, 2020.

The unaudited interim condensed consolidated financial statements have been prepared following the same accounting policies and methods of application as those in the Group's audited annual consolidated financial statements for the year ended December 31, 2019.

C. Going concern

The Group's unaudited interim condensed consolidated financial statements for the six months ended June 30, 2020, have been prepared on a going concern basis, which assumes that the Group will be able to realize its assets and discharge its liabilities in the normal course of business as they become due in the foreseeable future.

D. Changes in accounting policies and disclosures

During the six months ended June 30, 2020, the Group did not adopt any new standards and interpretations or amendments thereto applicable for financial periods beginning on or after January 1, 2020.

2. SEGMENT INFORMATION

The Group operates within several geographical areas. Operating segments are reported at a country level which is consistent with the internal reporting provided to the CEO, who is the chief operating decision maker.

The following tables present segment information regarding: revenue, production costs, exploration and evaluation costs and gross profit. The Group derives its revenue from contracts with customers primarily through the transfer of oil and gas at a point in time. In addition, certain identifiable asset segment information is reported in Notes 7 and 8.

	Three months ended – June 30, 2020				
USD Thousands	Canada	Malaysia[1]	France	Other	Total
Crude oil	13,687	7,080	5,952	–	**26,719**
NGLs	11	–	–	–	**11**
Gas	12,086	–	–	–	**12,086**
Net sales of oil and gas	**25,784**	**7,080**	**5,952**	**–**	**38,816**
Change in under/over lift position	–	–	(707)	–	**(707)**
Royalties	(765)	–	–	–	**(765)**
Hedging settlement	3,448	–	–	–	**3,448**
Other operating revenue	–	3,867	177	93	**4,137**
Revenue	**28,467**	**10,947**	**5,422**	**93**	**44,929**
Production costs (including inventory movements)	(27,003)	460	(3,532)	–	**(30,075)**
Depletion	(13,298)	(7,097)	(2,903)	–	**(23,298)**
Depreciation of other assets	–	(2,989)	–	–	**(2,989)**
Exploration and business development costs	(3,033)	68	(2,220)	81	**(5,104)**
Gross profit / (loss)	**(14,867)**	**1,389**	**(3,233)**	**174**	**(16,537)**

	Three months ended – June 30, 2019				
USD Thousands	Canada	Malaysia[1]	France	Other	Total
Crude oil	81,207	28,079	7,235	–	116,521
NGLs	80	–	–	–	80
Gas	17,775	–	–	–	17,775
Net sales of oil and gas	99,062	28,079	7,235	–	134,376
Change in under/over lift position	–	–	2,026	–	2,026
Royalties	(8,330)	–	–	–	(8,330)
Hedging settlement	(2,879)	–	–	–	(2,879)
Other operating revenue	–	3,868	177	119	4,164
Revenue	87,853	31,947	9,438	119	129,357
Production costs (including inventory movements)	(45,572)	(1,416)	(5,408)	–	(52,396)
Depletion	(19,036)	(8,043)	(2,618)	–	(29,697)
Depreciation of other assets	–	(7,789)	–	–	(7,789)
Exploration and business development costs	(14)	(2)	–	(172)	(188)
Gross profit	23,231	14,697	1,412	(53)	39,287

	Six months ended – June 30, 2020				
USD Thousands	Canada	Malaysia[1]	France	Other	Total
Crude oil	53,694	23,935	14,685	–	92,314
NGLs	88	–	–	–	88
Gas	26,872	–	–	–	26,872
Net sales of oil and gas	**80,654**	**23,935**	**14,685**	**–**	**119,274**
Change in under/over lift position	–	–	(4,064)	–	(4,064)
Royalties	(4,489)	–	–	–	(4,489)
Hedging settlement	6,301	–	–	–	6,301
Other operating revenue	–	7,735	453	255	8,443
Revenue	**82,466**	**31,670**	**11,074**	**255**	**125,465**
Production costs (including inventory movements)	(72,650)	(5,801)	(10,765)	–	**(89,216)**
Depletion	(31,352)	(14,304)	(7,916)	–	**(53,572)**
Depreciation of other assets	–	(6,024)	–	–	**(6,024)**
Exploration and business development costs	(3,033)	68	(2,220)	(441)	**(5,626)**
Gross profit / (loss)	**(24,569)**	**5,609**	**(9,827)**	**(186)**	**(28,973)**

	Six months ended – June 30, 2019				
USD Thousands	Canada	Malaysia[1]	France	Other	Total
Crude oil	154,421	64,491	18,948	–	237,860
NGLs	165	–	–	–	165
Gas	41,726	–	–	–	41,726
Net sales of oil and gas	196,312	64,491	18,948	–	279,751
Change in under/over lift position	–	–	5,296	–	5,296
Royalties	(14,250)	–	–	–	(14,250)
Hedging settlement	(2,380)	–	–	–	(2,380)
Other operating revenue	–	7,693	463	204	8,360
Revenue	179,682	72,184	24,707	204	276,777
Production costs (including inventory movements)	(91,176)	(11,465)	(12,528)	–	(115,169)
Depletion	(37,412)	(16,317)	(5,829)	–	(59,558)
Depreciation of other assets	–	(15,578)	–	–	(15,578)
Exploration and business development costs	(44)	(2)	–	(254)	(300)
Gross profit	51,050	28,822	6,350	(50)	86,172

[1] *The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.*

3. PRODUCTION COSTS

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Cost of operations	29,518	45,008	74,343	90,075
Tariff and transportation expenses	4,217	6,440	9,838	12,320
Direct production taxes	945	1,488	3,057	3,357
Operating costs	**34,680**	52,936	**87,238**	105,752
Cost of blending[1]	2,051	6,090	6,169	11,762
Change in inventory position	(6,656)	(6,630)	(4,191)	(2,345)
Total production costs	**30,075**	52,396	**89,216**	115,169

[1] In Canada, oil production is blended with purchased condensate diluent to meet pipeline specifications. Cost of blending represents the contracted purchase of diluent used for blending net of proceeds from the sale of surplus diluent. A net cost of USD 962 thousand and USD 746 thousand was recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q2 2020 and Q2 2019 respectively (USD 732 thousand and USD 1,153 for the first 6 months of 2020 and 2019 respectively).

4. FINANCE INCOME

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Foreign exchange gain, net	12,365	4,960	–	8,859
Interest income	13	52	68	106
Other	–	95	–	95
	12,378	5,107	**68**	9,060

5. FINANCE COSTS

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Foreign exchange loss, net	–	–	(9,492)	–
Interest expense	(2,563)	(7,277)	(6,350)	(11,571)
Unwinding of asset retirement obligation discount	(2,646)	(2,651)	(5,289)	(5,317)
Amortization of loan fees	(374)	(556)	(759)	(1,160)
Loan commitment fees	(246)	(494)	(541)	(838)
Other financial costs	(138)	(293)	(388)	(405)
	(5,967)	(11,271)	**(22,819)**	(19,291)

6. INCOME TAX

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Current tax	(112)	(465)	(26)	(2,056)
Deferred tax	11,861	(4,200)	16,114	(8,974)
Total tax	**11,749**	(4,665)	**16,088**	(11,030)

The deferred tax amount arises primarily where there is a difference in depletion for tax and accounting purposes. The deferred tax credit in the income statement in Q2 2020 mainly relates to the increased tax losses incurred during Q2 2020.

Specification of deferred tax assets and tax liabilities[1]

USD Thousands	June 30, 2020	December 31, 2019
Unused tax loss carry forward	123,185	92,855
Other	2,281	1,020
Deferred tax assets	**125,466**	93,875
Accelerated allowances	84,655	83,811
Other	377	106
Deferred tax liabilities	**85,032**	83,917
Deferred taxes, net	**40,434**	9,958

[1] The specification of deferred tax assets and tax liabilities does not agree to the face of the balance sheet due to the netting off of balances in the balance sheet when they relate to the same jurisdiction.

The deferred tax liabilities consist of accelerated allowances, being the difference between the book and the tax value of oil and gas properties. The deferred tax liabilities will be released over the life of the oil and gas assets as the book value is depleted for accounting purposes.

Deferred tax assets in relation to tax loss carried forwards are only recognized in so far that there is a reasonable certainty as to the timing and the extent of their realization. The recognized unused tax loss carry forward mainly relates to the acquisition of BlackPearl in December 2018 and to the Granite Acquisition (see Note 9).

7. EXPLORATION AND EVALUATION ASSETS

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2020	13,899	6,761	6,954	27,614
Additions	2,686	145	418	3,249
Expensed exploration and evaluation costs	(3,033)	68	(2,220)	(5,185)
Reclassification[1]	–	(6,487)	(51)	(6,538)
Currency translation adjustments	(703)	–	(52)	(755)
Net book value June 30, 2020	**12,849**	**487**	**5,049**	**18,385**

[1] The reclassification to the property, plant and equipment producing pool relates to the successful appraisal drilling in Malaysia.

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2019	–	2,844	6,600	9,444
Additions	13,654	17,330	477	31,461
Expensed exploration and evaluation costs	(44)	(13,413)	–	(13,457)
Currency translation adjustments	289	–	(123)	166
Net book value December 31, 2019	13,899	6,761	6,954	27,614

8. PROPERTY, PLANT AND EQUIPMENT, NET

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2020	905,394	493,231	385,775	1,784,400
Granite Acquisition (see Note 9)	47,076	–	–	47,076
Additions	32,189	20,055	7,119	59,363
Reclassification	–	6,487	51	6,538
Currency translation adjustments	(46,756)	–	(1,105)	(47,861)
June 30, 2020	**937,903**	**519,773**	**391,840**	**1,849,516**
Accumulated depletion				
January 1, 2020	(122,595)	(392,432)	(191,492)	(706,519)
Depletion charge for the period	(31,352)	(14,304)	(7,916)	(53,572)
Currency translation adjustments	6,273	–	469	6,742
June 30, 2020	**(147,674)**	**(406,736)**	**(198,939)**	**(753,349)**
Net book value June 30, 2020	**790,229**	**113,037**	**192,901**	**1,096,167**

USD Thousands	Canada	Malaysia	France	Total
Cost				
January 1, 2019	788,879	448,976	351,772	1,589,627
Acquisition of BlackPearl	12,346	–	–	12,346
Additions	72,719	36,714	39,693	149,126
Change in estimates	(9,204)	7,541	734	(929)
Currency translation adjustments	40,654	–	(6,424)	34,230
December 31, 2019	905,394	493,231	385,775	1,784,400
Accumulated depletion				
January 1, 2019	(41,257)	(362,071)	(180,875)	(584,203)
Depletion charge for the period	(77,677)	(30,077)	(13,905)	(121,659)
Write-off	–	(284)	–	(284)
Currency translation adjustments	(3,661)	–	3,288	(373)
December 31, 2019	(122,595)	(392,432)	(191,492)	(706,519)
Net book value December 31, 2019	782,799	100,799	194,283	1,077,881

Impairment test

In response to the significant decrease and volatility in commodity prices since December 31, 2019, the Group updated its impairment testing as at June 30, 2020. The Group used appropriate oil or natural gas price curves based on forward forecasts as at June 30, 2020, a future cost inflation factor of 2% per annum, production and cost profiles based on proved and probable reserves (2P reserves) as at December 31, 2019 and a discount rate of 8.5% (8% at December 31, 2019) to calculate the estimated future post-tax cash flows. As a result of the testing, the Group determined that no impairment of the recorded book value of the Group's oil and gas properties was required as at June 30, 2020. Sensitivity scenarios were run and showed that a USD 2/bbl decrease in the oil price curve would result in a pre-tax impairment charge of USD 7 million and the use of a discount rate of 10% would also result in a pre-tax impairment charge of USD 7 million.

The following prices were used in the impairment testing as at June 30, 2020:

Price Decks	2020	2021	2022	2023	2024	Average annual increase thereafter
Dated Brent (USD/bbl)	43.17	48.32	53.88	58.13	60.08	2%
West Texas Intermediate (USD/bbl)	39.00	44.59	51.13	57.22	58.98	2%
Western Canadian Select (USD/bbl)	26.86	30.13	36.50	41.75	43.34	2%
Empress Gas (CAD/MMbtu)	2.53	3.16	3.38	3.44	3.51	2%

9. GRANITE ACQUISITION

On March 5, 2020, IPC completed the acquisition of all of the issued and outstanding shares of Granite. At such date, Granite became a wholly-owned subsidiary of IPC.

The Granite Acquisition has been accounted for as a business combination in accordance with IFRS 3, with IPC being the acquirer.

Total consideration provided, after preliminary closing adjustments, amounted to USD 27.7 million (CAD 37.1 million).

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

USD Thousands	
Trade and other receivables	1,620
Prepaid expenses and deposits	599
Fair value of risk management assets	1,748
Deferred tax assets	16,730
Property, plant and equipment	47,076
Other fixed assets	85
Accounts payable and accrued liabilities	(6,691)
Decommissioning liabilities	(4,498)
Short-term debt	(27,649)
MTM reserve in equity	(1,311)
Total Consideration	**27,709**
Settled by:	
Cash payment for 39,061,575 common shares of Granite	**27,709**

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

Acquisition-related costs of approximately USD 0.5 million have been recognized in the income statement during the first six months of 2020.

Decommissioning obligations
The fair value of the decommissioning obligation at the acquisition date was based on the estimated future cash flows to decommission the acquired oil and natural gas properties at the end of their useful life. The discount rate used to determine the net present value of the decommissioning obligation was a credit risk adjusted rate of 8%.

10. OTHER TANGIBLE FIXED ASSETS, NET

USD Thousands	FPSO	Other	Total
Cost			
January 1, 2020	205,989	9,420	215,409
Granite Acquisition (see Note 9)	–	85	85
Additions	–	137	137
Currency translation adjustments	(72)	(160)	(232)
June 30, 2020	**205,917**	**9,482**	**215,399**
Accumulated depreciation			
January 1, 2020	(140,735)	(5,659)	(146,394)
Depreciation charge for the period	(6,024)	(418)	(6,442)
Currency translation adjustments	–	45	45
June 30, 2020	**(146,759)**	**(6,032)**	**(152,791)**
Net book value June 30, 2020	**59,158**	**3,450**	**62,608**

USD Thousands	FPSO	Other	Total
Cost			
January 1, 2019	206,421	9,203	215,624
Additions	–	1,035	1,035
Disposal	–	(838)	(838)
Currency translation adjustments	(432)	20	(412)
December 31, 2019	205,989	9,420	215,409
Accumulated depreciation			
January 1, 2019	(117,715)	(5,760)	(123,475)
Depreciation charge for the period	(23,020)	(786)	(23,806)
Disposal	–	838	838
Currency translation adjustments	–	49	49
December 31, 2019	(140,735)	(5,659)	(146,394)
Net book value December 31, 2019	65,254	3,761	69,015

The FPSO located on the Bertam field, Malaysia, is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves. The depreciation charge is included in the depreciation of other assets line in the income statement.

For office equipment and other assets, the depreciation charge for the year is based on cost and an estimated useful life of 3 to 5 years. The depreciation charge is included within the general, administration and depreciation expenses in the income statement.

11. OTHER ASSETS

USD Thousands	June 30, 2020	December 31, 2019
Long-term receivables	18,962	17,840
Financial assets	27	27
	18,989	17,867

Long-term receivables represent cash payments made to an asset retirement obligation fund in respect of the Bertam asset, Malaysia.

12. INVENTORIES

USD Thousands	June 30, 2020	December 31, 2019
Hydrocarbon stocks	10,468	6,123
Well supplies and operational spares	9,497	11,097
	19,965	17,220

13. TRADE AND OTHER RECEIVABLES

USD Thousands	June 30, 2020	December 31, 2019
Trade receivables	30,808	59,386
Underlift	1,102	5,250
Joint operations debtors	2,485	2,412
Prepaid expenses and accrued income	6,402	4,493
Other	1,474	6,293
	42,271	77,834

14. CASH AND CASH EQUIVALENTS

Cash and cash equivalents include only cash at hand or held in bank accounts.

15. SHARE CAPITAL

The Group's issued common share capital is as follows:

	Number of shares
Balance at January 1, 2019	163,720,065
Cancellation of repurchased common shares	(3,929,196)
Balance at December 31, 2019	**159,790,869**
Cancellation of repurchased common shares	(4,448,112)
Balance at June 30, 2020	**155,342,757**

The common shares of IPC trade on both the Toronto Stock Exchange and the Nasdaq Stockholm.

As at January 1, 2019, the total number of common shares issued and outstanding in IPC was 163,720,065.

On November 7, 2019, IPC announced the commencement of a share repurchase program. During the period up to March 31, 2020, IPC repurchased an aggregate of 8,377,308 common shares and all of these shares were cancelled. IPC suspended further share repurchases under the program. As at August 4, 2020, IPC had a total of 155,342,757 common shares issued and outstanding.

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, do not carry the right to vote on matters to be decided by the holders of IPC's common shares and are not included in the earnings per share calculations.

16. EARNINGS PER SHARE

Basic earnings per share are based on net result attributable to the common shareholders and is calculated based upon the weighted-average number of common shares outstanding during the periods presented.

	Three months ended June 30		Six months ended June 30	
	2020	2019	2020	2019
Net result attributable to shareholders of the Parent Company, USD	(1,469,958)	25,742,421	(41,529,177)	58,879,469
Weighted average number of shares for the period	155,293,334	163,720,065	157,554,525	163,720,065
Earnings per share, USD	**(0.01)**	0.16	**(0.26)**	0.36
Weighted average diluted number of shares for the period	156,720,254	166,567,604	158,981,446	166,567,604
Earnings per share fully diluted, USD	**(0.01)**	0.15	**(0.26)**	0.35

17. FINANCIAL LIABILITIES

USD Thousands	June 30, 2020	December 31, 2019
Bank loans	352,385	247,074
Capitalized financing fees	(3,417)	(2,342)
	348,968	244,732
Non-current	319,761	244,732
Current	29,207	–
	348,968	244,732

As at January 1, 2019, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had reserve-based lending credit facilities in aggregate of CAD 320 million and outstanding senior secured notes of CAD 75 million in connection with its oil and gas assets in Canada.

In June 2019, the Group combined its reserve-based lending facilities in Canada into one reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021. The senior secured notes of CAD 75 million were fully repaid and cancelled in June 2019, from a drawdown under the Canadian RBL.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France under a financial assistance program instituted by the French government authorities. The credit facility has an initial term of 12 months and is extendable by the Group for up to a further five years. The facility amount was fully drawn as at June 30, 2020.

In June 2020, the Group amended and extended the International RBL to a facility size of USD 125 million, with a maturity at the end of December 2024.

The borrowing base availability under the International RBL is currently USD 140 million of which USD 83 million was drawn as at June 30, 2020. The borrowing base availability under the Canadian RBL is currently CAD 350 million of which CAD 308.8 million was drawn as at June 30, 2020.

Also see Note 24 Subsequent Events.

In March 2020, in connection with the completion of the Granite Acquisition, the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility") of which CAD 40 million was outstanding at June 30, 2020. The Granite Facility has a maturity date of December 31, 2020 and is classified as current. Under the Granite Facility, IPC is required to hedge 40% of oil production from the assets acquired in the Granite Acquisition.

With the exception of the Granite Facility, no facility repayment schedule results in mandatory repayment within the next twelve months. As such, the amounts drawn under the International RBL and the Canadian RBL as at June 30, 2020, are classified as non-current.

The Group is in compliance with the covenants under the International RBL, the Canadian RBL and the Granite Facility as at June 30, 2020.

18. PROVISIONS

USD Thousands	Asset retirement obligation	Farm-in obligation	Pension obligation	Other	Total
January 1, 2020	176,305	6,720	4,413	2,399	189,837
Granite Acquisition (see Note 9)	4,498	–	–	–	4,498
Additions	–	–	–	1,088	1,088
Unwinding of asset retirement obligation discount	5,289	–	–	–	5,289
Payments	(2,727)	(615)	–	–	(3,342)
Reclassification[1]	1,967	–	–	–	1,967
Currency translation adjustments	(5,355)	(274)	–	(74)	(5,703)
June 30, 2020	**179,977**	**5,831**	**4,413**	**3,413**	**193,634**
Non-current	175,771	4,082	4,413	1,263	**185,529**
Current	4,206	1,749	–	2,150	**8,105**
Total	**179,977**	**5,831**	**4,413**	**3,413**	**193,634**

[1]The reclassification of the asset retirement obligation related to the 2020 payment to the asset retirement obligation fund in respect of the Bertam asset, Malaysia (see Note 11).

USD Thousands	Asset retirement obligation	Farm-in obligation	Pension obligation	Other	Total
January 1, 2019	168,537	6,047	–	5,638	180,222
Pension liability adjustment	–	–	3,223	–	3,223
Additions	–	–	697	227	924
Release of provisions	–	–	–	(2,004)	(2,004)
Unwinding of asset retirement obligation discount	10,664	–	–	–	10,664
Changes in estimates	(3,386)	2,457	959	–	30
Payments	(6,315)	(1,822)	(558)	(1,208)	(9,903)
Reclassification	2,413	–	–	(381)	2,032
Currency translation adjustments	4,392	38	92	127	4,649
December 31, 2019	176,305	6,720	4,413	2,399	189,837
Non-current	168,908	4,277	4,413	2,399	179,997
Current	7,397	2,443	–	–	9,840
Total	176,305	6,720	4,413	2,399	189,837

19. TRADE AND OTHER PAYABLES

USD Thousands	June 30, 2020	December 31, 2019
Trade payables	5,520	17,682
Joint operations creditors	16,353	24,164
Accrued expenses	31,293	40,317
Other	1,359	3,663
	54,525	85,826

20. FINANCIAL ASSETS AND LIABILITIES

Financial assets and liabilities by category

The accounting policies for financial instruments have been applied to the line items below:

June 30, 2020 USD Thousands	Total	Financial assets at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Other non-current financial assets	2,211	2,211	–	–
Other assets	18,989	18,989	–	–
Derivative instruments	1,595	–	–	1,595
Joint operation debtors	2,485	2,485	–	–
Other current receivables[1]	34,392	33,290	1,102	–
Cash and cash equivalents	11,018	11,018	–	–
Financial assets	**70,690**	**67,993**	**1,102**	**1,595**

[1] *Prepayments are not included in other current assets, as prepayments are not deemed to be financial instruments*

June 30, 2020 USD Thousands	Total	Financial liabilities at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Non-current financial liabilities	321,175	321,175	–	–
Current financial liabilities	29,207	29,207	–	–
Derivative instruments	2,565	–	–	2,565
Joint operation creditors	16,353	16,353	–	–
Other current liabilities	7,940	7,940	–	–
Financial liabilities	**377,240**	**374,675**	**–**	**2,565**

December 31, 2019 USD Thousands	Total	Financial assets at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Other non-current financial assets	2,700	2,700	–	–
Other assets	17,867	17,867	–	–
Derivative instruments	420	–	–	420
Joint operation debtors	2,412	2,412	–	–
Other current receivables[1]	71,925	66,675	5,250	–
Cash and cash equivalents	15,571	15,571	–	–
Financial assets	110,895	105,225	5,250	420

[1] *Prepayments are not included in other current assets, as prepayments are not deemed to be financial instruments*

December 31, 2019 USD Thousands	Total	Financial liabilities at amortized cost	Fair value recognized in profit or loss (FVTPL)	Derivatives used for hedging
Non-current financial liabilities	246,638	246,638	–	–
Derivative instruments	416	–	–	416
Joint operation creditors	24,164	24,164	–	–
Other current liabilities	24,895	24,895	–	–
Financial liabilities	296,113	295,697	–	416

For financial instruments measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:

- Level 1: based on quoted prices in active markets;
- Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
- Level 3: based on inputs which are not based on observable market data.

Based on this hierarchy, financial instruments measured at fair value can be detailed as follows:

June 30, 2020 USD Thousands	Level 1	Level 2	Level 3
Other current receivables	1,102	–	–
Derivative instruments – current	–	1,595	–
Financial assets	**1,102**	**1,595**	**–**
Derivative instruments – current	–	2,565	–
Financial liabilities	**–**	**2,565**	**–**

December 31, 2019 USD Thousands	Level 1	Level 2	Level 3
Other current receivables	5,250	–	–
Derivative instruments – current	–	420	–
Financial assets	5,250	420	–
Derivative instruments – current	–	416	–
Financial liabilities	–	416	–

The Group had gas price purchase hedges outstanding as at June 30, 2020, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
July 1, 2020 – December 31, 2020	4,000	Swap	AECO 5a + CAD 1.50/GJ

The Group had oil price sale hedges outstanding as at June 30, 2020, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
July 1, 2020 – September 30, 2020	700	Swap	WTI – CAD 70.67/bbl
October 1, 2020 – December 31, 2020	350	Swap	WTI – CAD 71.25/bbl
July 1, 2020 – July 31, 2020	6,600	Swap	WTI – USD 37.58/bbl
August 1, 2020 – August 31, 2020	8,700	Swap	WCS – USD 26.43/bbl
September 1, 2020 – September 30, 2020	9,200	Swap	WCS – USD 25.76/bbl
October 1, 2020 – December 31, 2020	7,550	Swap	WCS – USD 24.22/bbl
January 1, 2021 – March 31, 2021	200	Swap	WCS – USD 23.37/bbl

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

21. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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 18).

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, with four one-year options to extend such lease beyond the initial period, up to April 2025.

22. RELATED PARTIES

Lundin Energy (previously "Lundin Petroleum") has charged the Group USD 361 thousand in respect of office space rental and USD 417 thousand in respect of shared services provided during the first six months of 2020.

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.

23. IMPACT OF COVID-19

During Q1 2020, crude oil prices decreased substantially due to a drop in global oil demand triggered by the impact of the Covid-19 virus on the global economy and the lack of an agreement between OPEC and non-OPEC countries regarding proposed production cuts. OPEC and other countries agreed in April 2020 to decrease production. These production curtailments, as well as government stimulus programs and other improvements in general economic conditions, resulted in a strengthening of commodity prices, although still below levels existing prior to March 2020.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in IPC's 2019 Annual Information Form and previous financial reports and management's discussion and analysis that result from a reduction in demand for oil and gas consumption and/or lower commodity prices and/or reliance on third parties. The extent to which Covid-19 impacts IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of the current and any future Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition which could be more significant in upcoming periods as compared with the first half of 2020. Even after the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact.

As a result of these developments, IPC announced revised 2020 business plans in April 2020 and again in May 2020.

The Group will continue to monitor this situation and IPC will work to adapting its business to further developments as determined necessary or appropriate.

24. SUBSEQUENT EVENTS

In July 2020, the Group also entered into the following oil price sale hedges in Canada:

Period	Volume (barrels per day)	Type	Average Pricing
August 1, 2020 – August 31, 2020	600	Swap	WTI – USD 40.65/bbl
September 1, 2020 – September 30, 2020	700	Swap	WCS – USD 29.80/bbl
October 1, 2020 – December 31, 2020	500	Swap	WCS – USD 27.20/bbl

In July 2020, the International RBL facility size was increased to USD 140 million.

In July 2020, the Group also amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended by 12 months until the end of May 2022. Under the Canadian RBL, the Group is required to hedge a minimum of 30% of forecast production in Canada (other than in respect of assets acquired in the Granite Acquisition) for the period from October 1, 2020 to June 30, 2021. The Group is also restricted from incurring more than MCAD 10 of capital expenditures in Canada during the period from August to November 2020.

No other events have occurred since June 30, 2020, that are expected to have a substantial effect on this financial report. The implications of Covid-19 which continue to impact IPC's business also after June 30, 2020 are closely monitored by the Group.

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Q2

International Petroleum Corporation

Management's Discussion and Analysis

For the three and six months ended June 30, 2020

International Petroleum Corp.

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Non-IFRS Measures
References are made in this MD&A to “operating cash flow” (OCF), “free cash flow” (FCF), “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt” 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 similar measures presented by other public companies. The Corporation uses non-IFRS measures to provide investors with supplemental measures to assess 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 22.

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 27.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in Canada (including oil and gas assets acquired in the acquisition of Granite Oil Corp.) are effective as of December 31, 2019 and are included in the reports prepared by Sproule Associates Limited (Sproule), 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 Sproule’s December 31, 2019 price forecasts.

Reserve estimates, contingent 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, 2019, 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 Sproule’s December 31, 2019 price forecasts.

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

The Covid-19 virus and the restrictions and disruptions related to it, as well as the actions of certain oil and gas producing nations, had a drastic adverse effect in 2020 on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation’s common shares. During Q2 2020, commodity prices improved although such prices are still below historical levels and there can be no assurance that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC’s common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures. See “Risks and Uncertainties”.

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 4, 2020, 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, 2020 ("Financial Statements").

Formation of and changes in the Group

In April 2017, Lundin Energy AB (then known as Lundin Petroleum AB) 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.

On April 24, 2017, 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").

On March 5, 2020, IPC completed the acquisition of all of the issued and outstanding shares of Granite Oil Corp. ("Granite") by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Granite Acquisition").

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 France 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:

	June 30, 2020		June 30, 2019		December 31, 2019	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1015	1.1198	1.1298	1.1380	1.1196	1.1234
1 USD equals CAD	1.3648	1.3685	1.3337	1.3087	1.3270	1.2994
1 USD equals MYR	4.2519	4.2855	4.1195	4.1373	4.1422	4.0905

Q2 2020 HIGHLIGHTS

Business Update

- Forecast 2020 net average production revised upwards to 37,000 to 40,000 barrels of oil equivalent per day (boepd) from the previous guidance of 30,000 to 37,000 boepd.
- Capital and decommissioning expenditure guidance marginally increased by MUSD 3 to MUSD 80.
- Financial flexibility strengthened with the refinancing of our International and Canadian Reserve Based Lending (RBL) credit facilities in addition to securing a new MEUR 13 unsecured credit facility in France.
- Assuming average Brent oil prices of USD 35 per barrel and average Western Canadian Select (WCS) oil prices of USD 22 per barrel for the second half of 2020, IPC expects to be free cash flow[1] positive for that period and to have access to more than MUSD 100 of spare financial headroom by year end 2020.

Operational Highlights

- Average net production of approximately 35,700 boepd for Q2 2020 (31% heavy crude oil, 22% light and medium crude oil and 47% natural gas).
- Operating costs[1] of USD 10.7 per boe for Q2 2020, slightly ahead of Q1 guidance. Full year forecast retained at USD 12 to 13 per boe.

[1] *See definition on page 22 under "Non-IFRS measures"*

Financial Highlights

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Revenue	44,929	129,357	125,465	276,777
Gross profit / (loss)	(16,537)	39,287	(28,973)	86,172
Net result	(1,472)	25,744	(41,541)	58,886
Operating cash flow [1]	14,742	76,496	36,223	159,552
Free cash flow[1]	717	22,756	(41,995)	74,820
EBITDA [1]	12,187	74,600	31,196	156,275
Net Debt [1]	341,367	239,322	341,367	239,322

[1]*See definition on page 22 under "Non-IFRS measures"*

- Operating cash flow [1] generation for the second quarter 2020 amounted to MUSD 14.7, ahead of our latest forecast as a result of oil prices strengthening through June 2020. Moreover, as a result of our spending reductions, operational choices made and our hedging program, IPC was free cash flow[1] neutral during Q2 2020.
- Net debt [1] increased from MUSD 302.5 as at March 31, 2020 to MUSD 341.4 as at June 30, 2020.
- Refinancing of IPC's RBL credit facilities has been successfully concluded. The International RBL facility size has been increased from MUSD 125 to MUSD 140 and the maturity extended by two and a half years to the end of 2024. The Canadian RBL facility has been refinanced at MCAD 350 and extended until end May 2022. In addition, in early May 2020 and as previously disclosed, a MEUR 13 credit facility was secured in France.

OPERATIONS REVIEW

Business Overview
The second quarter of 2020 is certainly one that all of us are relieved to see is behind us. The global Covid-19 outbreak and the resulting confinement measures placed on the world's population led to a collapse in world oil demand, inventories approaching breaking point, and an unprecedented level of volatility and commodity price weakness.

Thankfully though, we have seen encouraging steps taken by OPEC+ and other oil producers that have removed significant supply, helping to deal with the massive demand destruction. Those actions have helped to flatten the curve of inventory builds and have set us on a course expected to rebalance markets in the second half of 2020 and into 2021.

With governments now progressively easing the restrictions that have been imposed to contain the pandemic, together with the enormous financial and fiscal stimulus packages that have been announced, prospects for a rebalancing of the oil market have improved and IPC has started to plan for a recovery in both demand and prices. Clearly though, uncertainties remain around a potential second wave of infections and the impact that could have will determine the pace and magnitude of recovery in oil demand. A recovery in oil prices is likely to take some time, and discipline and compliance on the supply side measures announced by OPEC+ will also be essential.

Update of 2020 Business Plan
Given that IPC operates the majority of our assets, we had the financial and operational flexibility to react swiftly to the situation and to positively position the Corporation to navigate through this period of extremely low commodity prices. All remaining discretionary 2020 expenditures were deferred or cancelled. In addition, during the second quarter of 2020, we took the decision to temporarily curtail production from those fields that were not expected to generate positive cash flows at the low pricing levels we were experiencing. These production curtailments related to a portion of our oil production. Our Canadian gas production was not curtailed as we continue to forecast positive cash flows.

In our latest Q1 2020 guidance, we revised our forecast 2020 net average production to be in the range of 30,000 to 37,000 boepd, estimated operating costs for 2020 to be in the range of USD 12 to 13 per boe, and reductions in total forecast 2020 expenditure of between MUSD 175 and 190 as compared to 2020 Capital Markets Day (CMD) estimates.

The upper end of our Q1 2020 production guidance assumed that curtailments implemented in Canada to the end of June 2020 continued through to the end of the year, with the lower end of the range assuming full curtailment of our Canadian oil production in the second half of 2020.

Given the improvement in our business outlook with strengthening oil prices, and in particular the strengthening in Canadian crude oil pricing, we have taken the decision to progressively bring back on stream our oil production from our Suffield Oil asset and our Onion Lake Thermal asset. In addition, in France, the temporary suspension of operations at the Total-operated Grandpuits refinery was lifted in early June and production from our Paris Basin assets has recovered to pre-curtailment levels.

As a result, we now forecast our 2020 net average production to be above the upper end of our previous guidance with a new range of 37,000 to 40,000 boepd.

Following these revisions, IPC's estimated 2020 capital and decommissioning expenditures are marginally increased by MUSD 3 to MUSD 80 and IPC's forecast 2020 unit operating costs are unchanged at USD 12 to 13 per boe.

Maximizing Financial Flexibility
During the second quarter of 2020, we have been working closely with our International and Canadian banking partners to maximize our financial flexibility.

We are pleased to report that we have successfully concluded our discussions with our international banking partners to increase and extend the maturity of our existing RBL facility. Our facility size is increased by MUSD 15 to MUSD 140 and the maturity is extended by two and a half years to the end of 2024. The facility size does not commence amortization until the second half of 2022 and is fully available.

In Canada, we also successfully concluded discussions with our banking partners. Our primary Canadian RBL facility, previously sized at MCAD 375 was refinanced at MCAD 350 and the maturity was extended by one year to end of May 2022. This new facility was concluded without having to access any of the financial support packages that were previously announced by the Canadian Federal Government, through Export Development Canada (EDC). Further, the leverage ratio was removed from the extended Canadian RBL facility and we are required to hedge a minimum of 30% of forecast production in Canada for the period from October 1, 2020 to June 30, 2021.

As previously disclosed in May 2020, IPC gained access to an unsecured French Government backed loan of MEUR 13. This unsecured loan carries the lowest margin of our loan portfolio and does not have any financial covenants.

Our overall cost of funding will increase slightly following the conclusion and extension of our finance facilities. Our weighted average cost of debt for the second half of 2020 is expected to increase to approximately 4.5%, an increase of around 1% compared with the first half of 2020 under the previous facilities but in line with the weighted average cost of debt of 2019.

In summary, during the second quarter of 2020, we have been able to increase the size of our available credit facilities by more than MUSD 10 whilst extending their maturities and removing any leverage ratio. This demonstrates the strong support we have been able to maintain from our banking partners.

Furthermore, IPC has decided to extend our Canadian oil price hedging program through the remainder of 2020 in order to lock in additional positive cash flow as we restore some of our curtailed production at our Suffield and Onion Lake properties. During June and July 2020, we have put in place additional oil hedges and have now hedged close to two thirds of our forecast Canadian oil production for the third quarter of 2020 and close to half of our forecast Canadian oil production for the fourth quarter of 2020 at WCS prices averaging USD 28 and 25 per barrel, respectively.

Having refinanced and extended the maturities of both our Canadian and International credit facilities in June and July 2020, we have now MUSD 90 of undrawn financial headroom. Assuming average second half 2020 Brent oil prices of USD 35 per barrel and average second half 2020 WCS oil prices of USD 22 per barrel, we expect to be free cash flow positive for the second half of 2020 and assuming the Granite credit facility is refinanced before the end of 2020, we project year end financial headroom in excess of MUSD 100. This represents a significant improvement from our first quarter guidance where we forecasted using up to 40% of that available headroom had commodity prices remained weak. This demonstrates that IPC has managed to preserve our financial resilience through this period of extreme volatility.

Second Quarter Performance

During the second quarter of 2020, our assets delivered average daily net production of 35,700 boepd, in line with our Q1 2020 guidance. Our operating costs per boe for the second quarter of 2020 was USD 10.7, slightly ahead of our Q1 2020 guidance.

Operating cash flow generation for the second quarter amounted to MUSD 14.7, ahead of our Q1 forecast as a result of oil prices strengthening through June. Moreover, as a result of our spending reductions, operational choices made and our hedging program, IPC was free cash flow neutral during the second quarter of 2020.

Capital and decommissioning expenditures during the second quarter of 2020 of MUSD 8.4 was in line with forecast and reflects the implementation of our expenditure reduction program previously announced.

Net debt increased during the second quarter of 2020 by MUSD 39 to MUSD 341. The increase was driven by non-cash exchange rate movements as a result of the Canadian dollar strengthening against the US dollar during the quarter (MUSD 10) as well as negative working capital movements (MUSD 29).

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 the second quarter of 2020, IPC recorded no material safety or environmental incidents.

In response to the Covid-19 outbreak, we are focused on protecting the health and safety of our employees, contractors and other stakeholders, while also working to ensure business continuity. In the second quarter of 2020, IPC continued the health protocols within its field operations and a work from home policy for employees whose work could be performed remotely.

Operations Overview

Reserves and Resources

The 2P reserves attributable to IPC oil and gas assets are 300 MMboe as at December 31, 2019 (including the 2P reserves attributable to the oil and gas assets acquired in the Granite Acquisition), as certified by an independent third party reserves auditor. The reserves life index (RLI) as at December 31, 2019 (including the 2P reserves attributable to the oil and gas assets acquired in the Granite Acquisition) was approximately 17 years. Best estimate contingent resources as at December 31, 2019, are 1,089 MMboe (unrisked) (and including the contingent resources attributable to the oil and gas assets acquired in the Granite Acquisition). Product types of 2P reserves and contingent resources are disclosed in the Corporation's Annual Information Form for the year ended December 31, 2019.

During the course of Q2 2020, in response to the low pricing environment, operational activities and development activity in all operating regions have been reduced, deferred or cancelled.

With the strengthening oil prices in the second half of Q2 2020, production and activity in Canada have increased in relation to the increase in pricing. IPC has initiated a detailed review of all deferred or cancelled operational and development activities to identify and prioritise those which generate positive returns at the current pricing levels.

Production

The average net production during Q2 2020 was slightly ahead of Q1 guidance at 35,700 boepd with a progressive production increase of the Suffield Oil and Onion Lake Thermal assets commencing in June 2020. In addition, the temporary suspension of operations at the Total-operated Grandpuits refinery was lifted and production from the Paris Basin assets returned to pre-curtailment levels in June 2020.

As a result of bringing production back on stream, we now forecast our 2020 net average production to be above the upper end of our previous guidance range at 37,000 to 40,000 boepd.

IPC's production during Q2 2020 with comparatives was comprised as follows:

Production in Mboepd	Three months ended June 30		Six months ended June 30		Year ended December 31
	2020	2019	2020	2019	2019
Crude oil					
Canada – Northern Assets	7.2	12.5	10.3	12.6	13.1
Canada – Southern Assets	5.0	6.4	6.4	6.4	6.4
Malaysia	4.6	6.2	4.6	6.3	5.8
France	1.9	2.0	2.6	2.2	2.5
Total crude oil production	**18.7**	**27.1**	**23.9**	**27.5**	27.8
Gas					
Canada - Northern Assets	0.1	0.1	0.1	0.1	0.1
Canada - Southern Assets	16.9	18.9	16.9	17.6	17.9
Total gas production	**17.0**	**19.0**	**17.0**	**17.7**	18.0
Total production	**35.7**	**46.1**	**40.9**	**45.2**	45.8
Quantity in MMboe	**3.25**	**4.19**	**7.44**	**8.19**	16.72

CANADA

Production in Mboepd	WI	Three months ended June 30 2020	Three months ended June 30 2019	Six months ended June 30 2020	Six months ended June 30 2019	Year ended December 31 2019
- Oil Onion Lake Thermal	100%	7.0	9.6	9.1	9.7	10.2
- Oil Suffield	100%	3.8	6.4	5.1	6.4	6.4
- Oil Ferguson	100%	1.2	–	1.3	–	–
- Oil Other	50 - 100%	0.2	2.9	1.2	2.9	2.9
- Gas	99.7%[1]	17.0	19.0	17.0	17.7	18.0
Canada		**29.2**	37.9	**33.7**	36.7	37.5

[1] *On a well count basis.*

Production

Net production from IPC's oil and gas assets in Canada during Q2 2020 was slightly ahead of Q1 guidance at 29,200 boepd with increased production from the Suffield Oil and the Onion Lake Thermal assets in June 2020.

During Q2 2020, with the strengthening of Canadian crude oil prices, IPC commenced a progressive oil production increase of the Suffield Oil and Onion Lake Thermal assets.

Organic Growth and Capital Projects

In Canada, IPC originally forecasted a comprehensive capital expenditure program including drilling, optimization and project work as part of the operational and capital budgets for 2020. As of the end of Q2 2020, in response to the extremely low pricing environment and the global Covid-19 outbreak, discretionary capital expenditure in Canada remains suspended, deferred or cancelled.

MALAYSIA

Production in Mboepd	WI	Three months ended June 30 2020	Three months ended June 30 2019	Six months ended June 30 2020	Six months ended June 30 2019	Year ended December 31 2019
Bertam	75%	**4.6**	6.2	**4.6**	6.3	5.8

Production

Net production from the Bertam field on Block PM307 during Q2 2020 was in line with guidance at 4,600 boepd. Exceptional operational performance continued at FPSO Bertam with facility uptime in excess of 99%.

Organic Growth and Capital Projects

At the end of Q2 2020, in response to the extremely low pricing environment and the global Covid-19 outbreak, all development activity in Malaysia remains suspended.

FRANCE

Production in Mboepd	WI	Three months ended June 30 2020	Three months ended June 30 2019	Six months ended June 30 2020	Six months ended June 30 2019	Year ended December 31 2019
France						
- Paris Basin	100% [1]	1.5	1.5	2.2	1.7	2.0
- Aquitaine	50%	0.4	0.5	0.4	0.5	0.5
		1.9	2.0	**2.6**	2.2	2.5

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

Production

Net production in France during Q2 2020 was slightly ahead of guidance at 1,900 boepd with the Total-operated Grandpuits oil refinery restarting in June 2020, alleviating oil export storage limitations and allowing a return to pre-curtailment production rates at the Paris Basin assets.

Organic Growth

At the end of Q2 2020, as a result of the extremely low pricing environment and the global Covid-19 outbreak, all further development activity in France remains suspended.

FINANCIAL REVIEW

Financial Results

Selected Interim Financial Information

Selected interim condensed consolidated statement of operations is as follows:

USD Thousands	Q2 2020	Q1 2020	Q4-19	Q3-19	Q2-19	Q1-19	Q4-18	Q3-18
Revenue	44,929	80,536	145,535	131.437	129,357	147,420	111,898	106,746
Gross profit / (loss)	(16,537)	(12,436)	43,245	23,487	39,287	46,885	26,311	37,060
Net result	(1,472)	(40,069)	38,372	6,330	25,744	33,142	29,346	26,487
Earnings per share – USD	(0.01)	(0.25)	0.23	0.04	0.16	0.20	0.29	0.30
Earnings per share fully diluted – USD	(0.01)	(0.25)	0.23	0.04	0.15	0.20	0.29	0.29
Operating cash flow[1]	14,742	21,481	78,888	69,504	76,496	83,056	58,322	67,949
EBITDA[1]	12,187	19,009	77,353	68,885	74,600	81,675	58,032	66,240
Net debt at period end[1]	341,367	302,473	231,503	207,778	239,322	256,962	276,761	213,217

[1] *See definition on page 22 under "Non-IFRS measures".*

Summarized consolidated balance sheet information is as follows:

USD Thousands	June 30, 2020	December 31, 2019
Non-current assets	1,281,467	1,252,600
Current assets	75,857	112,041
Total assets	1,357,324	1,364,641
Total non-current liabilities	549,377	474,200
Current liabilities	95,463	99,632
Total liabilities	644,840	573,832
Net assets	712,484	790,809
Working capital (including cash)	(19,606)	12,409

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) Canada – Northern Assets (comprising mainly of the Onion Lake Thermal asset) and (ii) Canada – Southern Assets (comprising of the Suffield Assets and the Ferguson asset). This is consistent with the internal reporting provided to IPC management. The following tables present certain segment information.

	Three months ended – June 30, 2020					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	5,997	7,690	7,080	5,952	–	**26,719**
NGLs	–	11	–	–	–	**11**
Gas	79	12,007	–	–	–	**12,086**
Net sales of oil and gas	**6,076**	**19,708**	**7,080**	**5,952**	**–**	**38,816**
Change in under/over lift position	–	–	–	(707)	–	**(707)**
Royalties	(527)	(238)	–	–	–	**(765)**
Hedging settlement	1,835	1,613	–	–	–	**3,448**
Other operating revenue	–	–	3,867	177	93	**4,137**
Revenue	**7,384**	**21,083**	**10,947**	**5,422**	**93**	**44,929**
Production costs (including inventory movements)	(10,605)	(16,398)	460	(3,532)	–	**(30,075)**
Depletion	(4,361)	(8,937)	(7,097)	(2,903)	–	**(23,298)**
Depreciation of other assets	–	–	(2,989)	–	–	**(2,989)**
Exploration and business development costs	(3,033)	–	68	(2,220)	81	**(5,104)**
Gross profit/(loss)	**(10,615)**	**(4,252)**	**1,389**	**(3,233)**	**174**	**(16,537)**

	Three months ended – June 30, 2019					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	47,183	34,024	28,079	7,235	–	116,521
NGLs	–	80	–	–	–	80
Gas	32	17,743	–	–	–	17,775
Net sales of oil and gas	47,215	51,847	28,079	7,235	–	134,376
Change in under/over lift position	–	–	–	2,026	–	2,026
Royalties	(5,651)	(2,679)	–	–	–	(8,330)
Hedging settlement	(2,505)	(374)	–	–	–	(2,879)
Other operating revenue	–	–	3,868	177	119	4,164
Revenue	39,059	48,794	31,947	9,438	119	129,357
Production costs (including inventory movements)	(17,677)	(27,895)	(1,416)	(5,408)	–	(52,396)
Depletion	(6,365)	(12,671)	(8,043)	(2,618)	–	(29,697)
Depreciation of other assets	–	–	(7,789)	–	–	(7,789)
Exploration and business development costs	(14)	–	(2)	–	(172)	(188)
Gross profit	15,003	8,228	14,697	1,412	(53)	39,287

USD Thousands	Six months ended – June 30, 2020					
	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	28,122	25,572	23,935	14,685	–	92,314
NGLs	–	88	–	–	–	88
Gas	151	26,721	–	–	–	26,872
Net sales of oil and gas	**28,273**	**52,381**	**23,935**	**14,685**	**–**	**119,274**
Change in under/over lift position	–	–	–	(4,064)	–	(4,064)
Royalties	(2,815)	(1,674)	–	–	–	(4,489)
Hedging settlement	4,165	2,136	–	–	–	6,301
Other operating revenue	–	–	7,735	453	255	8,443
Revenue	**29,623**	**52,843**	**31,670**	**11,074**	**255**	**125,465**
Production costs (including inventory movements)	(29,235)	(43,415)	(5,801)	(10,765)	–	**(89,216)**
Depletion	(12,591)	(18,761)	(14,304)	(7,916)	–	**(53,572)**
Depreciation of other assets	–	–	(6,024)	–	–	**(6,024)**
Exploration and business development costs	(3,033)	–	68	(2,220)	(441)	**(5,626)**
Gross profit/(loss)	**(15,236)**	**(9,333)**	**5,609**	**(9,827)**	**(186)**	**(28,973)**

USD Thousands	Six months ended – June 30, 2019					
	Canada – Northern Assets	Canada – Southern Assets	Malaysia[1]	France	Other	Total
Crude oil	88,252	66,169	64,491	18,948	–	237,860
NGLs	–	165	–	–	–	165
Gas	127	41,599	–	–	–	41,726
Net sales of oil and gas	88,379	107,933	64,491	18,948	–	279,751
Change in under/over lift position	–	–	–	5,296	–	5,296
Royalties	(10,380)	(3,870)	–	–	–	(14,250)
Hedging settlement	(2,006)	(374)	–	–	–	(2,380)
Other operating revenue	–	–	7,693	463	204	8,360
Revenue	75,993	103,689	72,184	24,707	204	276,777
Production costs (including inventory movements)	(34,548)	(56,628)	(11,465)	(12,528)	–	(115,169)
Depletion	(13,408)	(24,004)	(16,317)	(5,829)	–	(59,558)
Depreciation of other assets	–	–	(15,578)	–	–	(15,578)
Exploration and business development costs	(44)	–	(2)	–	(254)	(300)
Gross profit	27,993	23,057	28,822	6,350	(50)	86,172

[1] The segment Malaysia includes the FPSO Bertam which is owned by the Group. The self-to-self payment of the lease fee for the FPSO Bertam has been eliminated from the revenue and the production costs.

Three and six months ended June 30, 2020 Review

Revenue
Total revenue amounted to USD 44,929 thousand for Q2 2020 compared to USD 129,357 thousand for Q2 2019 and USD 125,465 thousand for the first six months of 2020 compared to USD 276,777 thousand for the first six months of 2019 and is analyzed as follows:

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Crude oil sales	26,719	116,521	92,314	237,860
Gas and NGL sales	12,097	17,855	26,960	41,891
Change in under/overlift position	(707)	2,026	(4,064)	5,296
Royalties	(765)	(8,330)	(4,489)	(14,250)
Hedging settlement	3,448	(2,879)	6,301	(2,380)
Other operating revenue	4,137	4,164	8,443	8,360
Total revenue	**44,929**	129,357	**125,465**	276,777

The components of total revenue for the three and six months ended June 30, 2020 and June 30, 2019, respectively are detailed below.

Crude oil sales

	Three months ended – June 30, 2020				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	5,997	7,690	7,080	5,952	**26,719**
- Quantity sold in bbls	658,117	527,562	224,001	247,169	**1,656,849**
- Average price realized USD per bbl	9.11	14.58	31.61	24.08	**16.13**

	Three months ended – June 30, 2019				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	47,183	34,024	28,079	7,235	116,521
- Quantity sold in bbls	1,105,970	661,398	382,452	105,957	2,255,777
- Average price realized USD per bbl	42.66	51.44	73.42	68.28	51.65

Crude oil revenue was 77% lower for Q2 2020 compared to Q2 2019 due to lower oil prices resulting from a drop in global oil demand triggered by the impact of the global Covid-19 outbreak and the consequential partial curtailment of production as a response to the low oil prices. Crude oil prices started to recover towards the end of Q2 2020 and the Group commenced the progressive increase of Canadian oil production and entered into additional oil price hedges in relation to a proportion of the Canadian oil production for the second half of the year.

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 Q2 2020, WTI averaged USD 28 per bbl compared to USD 60 per bbl for Q2 2019 and the average discount from WTI to WCS used in our pricing formula was USD 11 per bbl (USD 11 per bbl for Q2 2019). Oil prices improved in the latter part of Q2 2020 with WTI averaging USD 38 per bbl in June 2020.

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.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices with revenue in France based on one month forward Brent prices. There were two cargo liftings in Malaysia during Q2 2020 with one lifting in April and one lifting in June. There was also one cargo of approximately 130,000 bbls lifted in April in relation to the French Aquitaine fields and it is the only cargo forecast to be lifted during 2020 for these fields. The average Dated Brent crude oil price was USD 30 per bbl for Q2 2020 compared to USD 69 per bbl for the comparative period.

	Six months ended – June 30, 2020				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	28,122	25,572	23,935	14,685	**92,314**
- Quantity sold in bbls	1,868,024	1,205,057	568,562	507,174	**4,148,817**
- Average price realized USD per bbl	15.05	21.22	42.10	28.96	**22.25**

	Six months ended – June 30, 2019				
	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	88,252	66,169	64,491	18,948	237,860
- Quantity sold in bbls	2,208,898	1,362,484	920,147	287,567	4,779,096
- Average price realized USD per bbl	39.95	48.56	70.09	65.89	49.77

Crude oil sales were 61% lower for the first six months of 2020 compared to the first six months of 2019 mainly due to a 55% reduction in achieved oil prices as a result of the drop in global oil demand triggered by the impact of the Covid-19 outbreak.

The Canadian realized sales price is based on the WCS price which is traded at a discount to WTI. WTI averaged USD 37 per bbl and the average discount from WTI to WCS was approximately USD 16 per bbl for the first six months of 2020, compared to an average WTI of USD 57 per bbl and an average discount from WTI to WCS of USD 11.50 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Brent crude oil prices and the average market Brent crude oil price was USD 40 per bbl in the first six months of 2020 compared to USD 66 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – June 30, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	12,018	79	**12,097**
- Quantity sold in Mcf	8,669,351	54,514	**8,723,865**
- Average price realized USD per Mcf	1.39	1.44	**1.39**

	Three months ended – June 30, 2019		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	17,825	32	17,855
- Quantity sold in Mcf	9,760,668	53,228	9,813,896
- Average price realized USD per Mcf	1.83	0.60	1.82

Gas and NGL sales revenue was 32% lower for Q2 2020 compared to Q2 2019 mainly due to the lower 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.

	Six months ended – June 30, 2020		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	26,809	151	**26,960**
- Quantity sold in Mcf	17,326,824	113,198	**17,440,022**
- Average price realized USD per Mcf	1.55	1.33	**1.55**

	Six months ended – June 30, 2019		
	Canada – Southern Assets	Canada – Northern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	41,764	127	41,891
- Quantity sold in Mcf	17,959,495	105,549	18,065,044
- Average price realized USD per Mcf	2.33	1.20	2.32

In Canada, gas and NGL sales revenue was 36% lower for the first six months of 2020 compared to the first six months of 2019 mainly due to the lower achieved gas price. For the first six months of 2020, IPC realized an average price of CAD 1.82 per Mcf compared to CAD 3.08 per Mcf for the first six months of 2019.

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 swaps and collars to limit pricing exposure. IPC also 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 settlements for Q2 2020 amounted to a gain of USD 3,448 thousand and for the first six months of 2020, amounted to a gain of USD 6,301 thousand and consisted of a gain of USD 221 thousand on the gas contracts and a gain of USD 6,080 thousand on the oil contracts. Also see the Financial Risk Management section below.

Other operating revenue

Other operating revenue amounted to USD 4,137 thousand for Q2 2020 compared to USD 4,164 thousand for Q2 2019 and USD 8,443 thousand for the first six months of 2020 compared to USD 8,360 thousand for the first six months of 2019. Other operating revenue 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.

Production costs

Production costs including inventory movements amounted to USD 30,075 thousand for Q2 2020 compared to USD 52,396 thousand for Q2 2019 and USD 89,216 thousand for the first six months of 2020 compared to USD 115,169 thousand for the first six months of 2019 and is analyzed as follows:

	Three months ended – June 30, 2020					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	14,767	10,605	16,443	4,467	(11,602)	34,680
USD/boe[2]	7.42	15.89	39.64	25.38	n/a	10.67
Cost of blending	2,051	–	–	–	–	**2,051**
Change in inventory position	(420)	–	(5,301)	(935)	–	**(6,656)**
Production costs	**16,398**	**10,605**	**11,142**	**3,532**	**(11,602)**	**30,075**

	Three months ended – June 30, 2019					
USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	21,683	17,677	18,321	6,858	(11,603)	52,936
USD/boe[2]	9.42	15.37	32.48	38.59	n/a	12.62
Cost of blending	6,090	–	–	–	–	**6,090**
Change in inventory position	122	–	(5,302)	(1,450)	–	**(6,630)**
Production costs	**27,895**	**17,677**	**13,019**	**5,408**	**(11,603)**	**52,396**

USD Thousands	Six months ended – June 30, 2020					
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	37,047	29,235	33,251	10,910	(23,205)	87,238
USD/boe[2]	8.73	15.41	39.77	23.25	n/a	11.72
Cost of blending	6,169	–	–	–	–	6,169
Change in inventory position	199	–	(4,245)	(145)	–	(4,191)
Production costs	**43,415**	**29,235**	**29,006**	**10,765**	**(23,205)**	**89,216**

USD Thousands	Six months ended – June 30, 2019					
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	44,915	34,598	35,862	13,505	(23,078)	105,752
USD/boe[2]	10.33	15.02	31.34	34.16	n/a	12.91
Cost of blending	11,762	–	–	–	–	11,762
Change in inventory position	(49)	–	(1,319)	(977)	–	(2,345)
Production costs	**56,628**	**34,598**	**34,543**	**12,528**	**(23,078)**	**115,169**

[1] *See definition on page 23 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 11.67 and USD 11.91 for Q2 2020 and Q2 2019 respectively and USD 12.02 and USD 11.17 for the six months ended June 30, 2020 and June 30, 2019 respectively.*

Operating costs

Operating costs amounted to USD 34,680 thousand for Q2 2020 compared to USD 52,936 thousand for Q2 2019 and USD 87,238 thousand for the first six months of 2020 compared to USD 105,752 thousand for the first six months of 2019. Operating costs per boe amounted to USD 10.67 per boe in Q2 2020 compared with USD 12.62 per boe in Q2 2019. Operating costs were lower in Q2 2020 as a result of curtailing uneconomic production and cancelling or deferring discretionary expenditure in response to the lower oil prices. Higher cost production barrels were curtailed during the quarter resulting in a lower average operating cost per barrel in the second quarter of 2020 compared to the first quarter.

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 2,051 thousand for Q2 2020 compared to USD 6,090 thousand for Q2 2019 and USD 6,169 thousand for the first six months of 2020 compared to USD 11,762 thousand for the first six months of 2019. The cost of blending was lower in Q2 2020 as diluent prices fell in line with reduced oil prices.

As a result of the blending, actual sales volumes are higher than produced barrels. A cost of USD 962 thousand and USD 746 thousand were recognized relating to the difference between the cost and sale proceeds of the surplus diluent for Q2 2020 and Q2 2019, respectively. A cost of USD 732 thousand and USD 1,153 thousand were recognized for the six months ended June 30, 2020 and June 30, 2019, 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.

Depletion and decommissioning costs

The total depletion and decommissioning costs amounted to USD 23,298 thousand for Q2 2020 compared to USD 29,697 thousand for Q2 2019 and USD 53,572 thousand for the first six months of 2020 compared to USD 59,558 thousand for the first six months of 2019. The depletion charge is analyzed in the following tables:

	Three months ended – June 30, 2020				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	8,937	4,361	7,097	2,903	**23,298**
USD per boe	4.49	6.54	17.11	16.50	**7.17**

	Three months ended – June 30, 2019				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	12,671	6,365	8,043	2,618	29,697
USD per boe	5.50	5.53	14.26	14.73	7.08

	Six months ended – June 30, 2020				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	18,761	12,591	14,304	7,916	**53,572**
USD per boe	4.42	6.64	17.11	16.87	**7.20**

	Six months ended – June 30, 2019				
	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Depletion cost in USD thousands	24,004	13,408	16,317	5,829	59,558
USD per boe	5.52	5.83	14.26	14.74	7.27

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 2,989 thousand for Q2 2020 compared to USD 7,789 thousand for Q2 2019 and USD 6,024 thousand for the first six months of 2020 compared to USD 15,578 thousand for the first six months of 2019. This related to the depreciation of the FPSO Bertam, which is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves. Prior to this date the Bertam FPSO was being depreciated on a straight line basis over the six year lease period on the Bertam field from April 2015.

Exploration and business development costs

The total exploration and business developments costs amounted to USD 5,104 thousand for Q2 2020. These costs mainly related to exploration costs expensed in France as future development on the exploration licences is unlikely and to appraisal wells drilled in Canada in 2019 where performance was below expectation.

General, administrative and depreciation expenses

General, administrative and depreciation expenses amounted to USD 3,095 thousand for Q2 2020 compared to USD 2,714 thousand for Q2 2019 and USD 5,905 thousand for the first six months of 2020 compared to USD 6,025 thousand for the first six months of 2019.

Net financial items

Net financial items for Q2 2020 amounted to a credit of USD 6,411 thousand compared to a charge of USD 6,164 thousand for Q2 2019 and a charge of USD 22,751 thousand for the first six months of 2020 compared to a charge of USD 10,231 thousand for the first six months of 2019 and include largely non-cash net foreign exchange movements mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements, the net financial items amounted to a charge of USD 5,954 thousand for Q2 2020, compared to a charge of USD 11,124 thousand for Q2 2019 and a charge of USD 13,259 thousand for the first six months of 2020 compared to a charge of USD 19,090 thousand for the first six months of 2019.

The interest expense for Q2 2020 amounted to USD 2,563 thousand compared to USD 7,277 thousand for Q2 2019 and USD 6,350 thousand for the first six months of 2020 compared to USD 11,571 thousand for the first six months of 2019.The comparative interest expense in 2019 includes interest on senior notes acquired on the BlackPearl acquisition and the make whole provision costs when repaying these in Q2 2019.

The unwinding of the asset retirement obligation discount rate amounted to USD 2,646 thousand for Q2 2020 compared to USD 2,651 thousand for Q2 2019 and USD 5,289 thousand for the first six months of 2020 compared to USD 5,317 thousand for the first six months of 2019.

Income tax

The corporate income tax for Q2 2020 amounted a credit of USD 11,749 thousand compared to a charge of USD 4,665 thousand for Q2 2019 and a credit of USD 16,088 thousand for the first six months of 2020 compared to a charge of USD 11,030 thousand for the first six months of 2019. The income tax movements in the first six months of 2020 relate to deferred taxes with minimal cash taxes reflected.

Capital Expenditure

Development and exploration and evaluation expenditure incurred in the first six months of 2020, was as follows:

USD Thousands	Canada – Southern Assets	Canada – Northern Assets	Malaysia	France	Total
Development	11,148	21,041	20,055	7,119	**59,363**
Exploration and evaluation	–	2,686	145	418	**3,249**
	11,148	23,727	20,200	7,537	**62,612**

Capital expenditure of USD 62,612 thousand was mainly spent on drilling on the Suffield Assets, the development of the Pad D' on Onion Lake Thermal and the continued drilling campaign in Malaysia. USD 56,190 thousand of the capital expenditure was spent in Q1 2020, with discretionary capital spend cancelled or deferred thereafter when oil prices collapsed. The capital expenditure forecast for 2020 including abandonment costs is forecasted at USD 80 million.

Other tangible fixed assets

Other tangible fixed assets amounted to USD 62,608 thousand as at June 30, 2020, which included USD 59,158 thousand in respect of the FPSO Bertam. The FPSO Bertam is being depreciated on a unit of production basis from July 2019 based on the Bertam field 2P reserves.

Granite Acquisition

On March 5, 2020, IPC completed the acquisition of all of the issued and outstanding shares of Granite. At such date, Granite became a wholly-owned subsidiary of IPC.

The Granite Acquisition has been accounted for as a business combination in accordance with IFRS 3, with IPC being the acquirer. Total consideration provided, after preliminary closing adjustments, amounted to USD 27.7 million (CAD 37.1 million).

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

USD Thousands	
Trade and other receivables	1,620
Prepaid expenses and deposits	599
Fair value of risk management assets	1,748
Deferred tax assets	16,730
Property, plant and equipment	47,076
Other fixed assets	85
Accounts payable and accrued liabilities	(6,691)
Decommissioning liabilities	(4,498)
Long-term debt	(27,649)
MTM reserve in equity	(1,311)
Total Consideration	**27,709**
Settled by:	
Cash payment for 39,061,575 common shares of Granite	27,709

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

Acquisition-related costs of approximately USD 0.5 million have been recognized in the income statement for the first six months of 2020.

Financial Position and Liquidity

Financing

As at January 1, 2019, the Group had a reserve-based lending credit facility of USD 175 million (the "International RBL") with a maturity to end June 2022 in connection with its oil and gas assets in France and Malaysia. In addition, the Group had reserve-based lending credit facilities in aggregate of CAD 320 million and outstanding senior secured notes of CAD 75 million in connection with its oil and gas assets in Canada.

In June 2019, the Group combined its reserve-based lending facilities in Canada into one reserve-based lending credit facility of CAD 375 million (the "Canadian RBL") with a maturity date in May 2021. The senior secured notes of CAD 75 million were fully repaid and cancelled in June 2019, from a drawdown under the Canadian RBL.

In May 2020, IPC entered into a EUR 13 million unsecured credit facility in France under a financial assistance program instituted by the French government. The credit facility has an initial term of 12 months and is extendable by the Group for up to a further five years. The facility amount was fully drawn as at June 30, 2020 and as at the date of this MD&A.

In June 2020, the Group amended and extended the International RBL to a facility size of USD 125 million, with a maturity at the end of December 2024. In July 2020, the facility size was further increased to USD 140 million.

In July 2020, the Group also amended and extended the Canadian RBL to a facility size of CAD 350 million with a maturity extended by 12 months until the end of May 2022. Under the Canadian RBL, the Group is required to hedge a minimum of 30% of forecast production in Canada (other than in respect of assets acquired in the Granite Acquisition) for the period from October 1, 2020 to June 30, 2021. The Group is also restricted from incurring more than MCAD 10 of capital expenditures in Canada during the period from August to November 2020.

The borrowing base availability under the International RBL is currently USD 140 million of which USD 83 million was drawn as at June 30, 2020. The borrowing base availability under the Canadian RBL is currently CAD 350 million of which CAD 308.8 million was drawn as at June 30, 2020.

In March 2020, in connection with the completion of the Granite Acquisition, the Group assumed the bank debt of Granite consisting of a revolving credit facility of CAD 42.5 million (the "Granite Facility") of which CAD 40 million was drawn at June 30, 2020. The Granite Facility has a maturity date of December 31, 2020 and is classified as current. Under the Granite Facility, IPC is required to hedge 40% of oil production from the assets acquired in the Granite Acquisition.

Total net debt as at June 30, 2020, amounted to USD 341.4 million.

With the exception of the Granite Facility, no facility repayment schedule results in mandatory repayment within the next twelve months. As such, the amounts drawn under the International RBL and the Canadian RBL as at June 30, 2020, are classified as non-current.

The Group is in compliance with the covenants under the International RBL, the Canadian RBL and the Granite Facility as at June 30, 2020.

Cash and cash equivalents held amounted to USD 11,018 thousand as at June 30, 2020. The Corporation holds cash to meet imminent operational funding requirements in the different countries.

Working Capital

As at June 30, 2020, the Group had a net working capital balance including cash of USD (19,606) thousand compared to USD 12,409 thousand as at December 31, 2019. The change is mainly as a result of lower trade receivables at June 30, 2020 due to the lower oil price and the inclusion of USD 29,207 of short term external debt relating to the Granite acquisition.

Non-IFRS Measures

In addition to using financial measures prescribed under IFRS, references are made in this MD&A to "operating cash flow", "free 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 to assess cash generated by and the financial performance and condition of the Corporation. 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.

"Free cash flow" is calculated as operating cash flow less capital expenditures less abandonment and farm-in expenditures less general, administration and depreciation expenses before depreciation and less cash financial items. Free cash flow is used to analyze the amount of cash that is being generated by the business and that is available for such purposes as repaying debt, funding acquisitions and returning capital to shareholders.

"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.

Reconciliation of Non-IFRS Measures

Operating cash flow
The following table sets out how operating cash flow is calculated from figures shown in the Financial Statements:

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Revenue	44,929	129,357	125,465	276,777
Production costs	(30,075)	(52,396)	(89,216)	(115,169)
Current tax	(112)	(465)	(26)	(2,056)
Operating cash flow	**14,742**	76,496	**36,223**	159,552

Free cash flow

The following table sets out how free cash flow is calculated from figures shown in the Financial Statements:

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Operating cash flow - see above	14,742	76,496	36,223	159,552
Capital expenditures	(6,422)	(39,556)	(62,612)	(61,442)
Abandonment and farm-in expenditures[1]	(2,002)	(3,906)	(3,342)	(5,344)
General, administration and depreciation expenses before depreciation[2]	(2,667)	(2,361)	(5,053)	(5,333)
Cash financial items[3]	(2,934)	(7,917)	(7,211)	(12,613)
Free cash flow	**717**	22,756	**(41,995)**	74,820

[1] *See note 18 to the Financial Statements*

[2] *Depreciation is not specifically disclosed in the Financial Statements*

[3] *See notes 4 and 5 to the Financial Statements.*

EBITDA

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

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Net result	(1,472)	25,744	(41,541)	58,886
Net financial items	(6,411)	6,164	22,751	10,231
Income tax	(11,749)	4,665	(16,088)	11,030
Depletion	23,298	29,697	53,572	59,558
Depreciation of other assets	2,989	7,789	6,024	15,578
Exploration and business development costs	5,104	188	5,626	300
Depreciation included in general, administration and depreciation expenses [1]	428	353	852	692
EBITDA	**12,187**	74,600	**31,196**	156,275

[1] *Item is not shown in the Financial Statements*

Operating costs

The following table sets out how operating costs is calculated:

	Three months ended June 30		Six months ended June 30	
USD Thousands	2020	2019	2020	2019
Production costs	30,075	52,396	89,216	115,169
Cost of blending[1]	(2,051)	(6,090)	(6,169)	(11,762)
Change in inventory position	6,656	6,630	4,191	2,345
Operating costs	**34,680**	52,936	**87,238**	105,752

[1] *Item is not shown in the Financial Statements. See production costs section above.*

Net debt
The following table sets out how net debt is calculated from figures shown in the Financial Statements:

USD Thousands	June 30, 2020	December 31, 2019
Bank loans	352,385	247,074
Cash and cash equivalents	(11,018)	(15,571)
	341,367	231,503

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, has 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 outstanding until December 2020.

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

In connection with the Granite Acquisition, IPC, through its subsidiary Granite Oil Corp., has issued a letter of credit for an amount of CAD 500,000 in respect of its obligations related to the Ferguson asset. This letter of credit increases by CAD 100,000 annually, to a maximum of CAD 1,000,000.

Outstanding Share Data

The common shares of IPC trade on both the Toronto Stock Exchange and the Nasdaq Stockholm.

As at January 1, 2019, the total number of common shares issued and outstanding in IPC was 163,720,065. On November 7, 2019, IPC announced the commencement of a share repurchase program. During the period up to March 31, 2020, IPC repurchased an aggregate of 8,377,308 common shares and all of these shares were cancelled. IPC suspended further share repurchases under the program. As at August 4, 2020, IPC had a total of 155,342,757 common shares issued and outstanding.

Nemesia S.à.r.l. and Zebra Holdings and Investments S.à.r.l., investment companies wholly owned by a Lundin family trust, own 40,697,533 common shares in IPC, representing 26.20% of the outstanding common shares as at August 4, 2020.

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 1,808,566 stock options and 3,949,821 IPC Performance and Restricted Share Plan awards (632,973 awards granted in July 2018, 186,472 awards granted in March 2019, 1,337,822 awards granted in July 2019, 25,349 awards granted in January 2020, 1,741,870 awards granted in March 2020 and 25,335 awards granted in July 2020) outstanding as at August 4, 2020.

Contractual Obligations and Commitments

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 18 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, with four one-year options to extend such lease beyond the initial period, up to April 2025.

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

Lundin Energy (previously "Lundin Petroleum") has charged the Group USD 361 thousand in respect of office space rental and USD 417 thousand in respect of shared services provided during the first six months of 2020.

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 June 30, 2020, 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.

The Group had gas price purchase hedges outstanding as at June 30, 2020, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
July 1, 2020 – December 31, 2020	4,000	Swap	AECO 5a + CAD 1.50/GJ

The Group had oil price sale hedges outstanding as at June 30, 2020, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
July 1, 2020 – September 30, 2020	700	Swap	WTI – CAD 70.67/bbl
October 1, 2020 – December 31, 2020	350	Swap	WTI – CAD 71.25/bbl
July 1, 2020 – July 31, 2020	6,600	Swap	WTI – USD 37.58/bbl
August 1, 2020 – August 31, 2020	8,700	Swap	WCS – USD 26.43/bbl
September 1, 2020 – September 30, 2020	9,200	Swap	WCS – USD 25.76/bbl
October 1, 2020 – December 31, 2020	7,550	Swap	WCS – USD 24.22/bbl
January 1, 2021 – March 31, 2021	200	Swap	WCS – USD 23.37/bbl

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 asset of USD (970) thousand at June 30, 2020.

In July 2020, the Group also entered into the following oil price sale hedges in Canada:

Period	Volume (barrels per day)	Type	Average Pricing
August 1, 2020 – August 31, 2020	600	Swap	WTI – USD 40.65/bbl
September 1, 2020 – September 30, 2020	700	Swap	WCS – USD 29.80/bbl
October 1, 2020 – December 31, 2020	500	Swap	WCS – USD 27.20/bbl

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, 2019 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.

The current and any future Covid-19 outbreaks may increase IPC's exposure to, and magnitude of, each of the risks and uncertainties identified in these documents that result from a reduction in demand for oil and gas consumption and/or lower commodity prices and/or reliance on third parties. The extent to which Covid-19 impacts IPC's business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of the current and any future Covid-19 outbreaks, their severity, the actions taken to contain such outbreaks or treat their impact, and how quickly and to what extent normal economic and operating conditions resume and their impacts to IPC's business, results of operations and financial condition which could be more significant in upcoming periods as compared with the first half of 2020. Even after the Covid-19 outbreaks have subsided, IPC may continue to experience materially adverse impacts to IPC's business as a result of the global economic impact.

The Covid-19 virus and the restrictions and disruptions related to it, as well as the actions of certain oil and gas producing nations, had a drastic adverse effect in 2020 on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation's common shares. During Q2 2020, commodity prices improved although such prices are still below historical levels and there can be no assurance that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at August 4, 2020, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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 six and twelve month periods ended June 30, 2020, 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 Granite

The Granite 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 operating effectiveness of disclosure controls and procedures and internal controls over financial reporting in respect of these assets.

Summary financial information related to Granite is presented above.

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 such statements were made, 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.

The Covid-19 virus and the restrictions and disruptions related to it, as well as the actions of certain oil and gas producing nations, had a drastic adverse effect in 2020 on the world demand for, and prices of, oil and gas as well as the market price of the shares of oil and gas companies generally, including the Corporation's common shares. During Q2 2020, commodity prices improved although such prices are still below historical levels and there can be no assurance that commodity prices will not decrease or remain volatile in the future. These factors are beyond the control of the Corporation and it is difficult to assess how these, and other factors, will continue to affect the Corporation and the market price of IPC's common shares. In light of the current situation, as at the date of this MD&A, the Corporation continues to review and assess its business plans and assumptions regarding the business environment, as well as its estimates of future production, cash flows, operating costs and capital expenditures.

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:

- IPC's ability to maximize liquidity and financial flexibility in connection with the current and any future Covid-19 outbreaks and reductions in commodity prices;
- the expectation that recent actions will assist in reducing inventory builds and in rebalancing markets, including supply and demand for oil and gas;
- 2020 production range, operating costs and capital and decommissioning expenditure estimates;
- estimates of future production, cash flows, operating costs and capital expenditures that are based on IPC's current business plans and assumptions regarding the business environment, which are subject to change;
- IPC's ability to reduce expenditures to forecast levels;
- IPC's financial and operational flexibility to react to recent events and to prepare the Corporation to navigate through periods of low commodity prices;
- IPC's ability to defer or cancel expenditures and to curtail production, and to resume such production to expected levels following curtailment;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- the ability to fully fund 2020 expenditures from cash flows and current borrowing capacity;
- IPC's flexibility to remain within existing financial headroom;
- IPC's ability to maintain operations, production and business in light of the current and any future Covid-19 outbreaks and the restrictions and disruptions related thereto, including risks related to production delays and interruptions, changes in laws and regulations and reliance on third-party operators and infrastructure;
- IPC's intention and ability to continue to implement our strategies to build long-term shareholder value;
- the ability of IPC's portfolio of assets to provide a solid foundation for organic and inorganic growth;
- the continued facility uptime and reservoir performance in IPC's areas of operation;
- future development potential of the Suffield operations, including future oil drilling and gas optimization programs, the ability to offset natural declines and the N2N EOR development project;
- development of the Blackrod project in Canada;
- the results of the facility optimization program, the work to debottleneck the facilities and injection capability and the current and future drilling pad production, as well as water intake and steam generation issues, at Onion Lake Thermal;
- the ability of IPC to achieve and maintain current and forecast production and take advantage of production growth and development upside opportunities related to the oil and gas assets acquired in the Granite Acquisition;
- the ability of existing infrastructure acquired in the Granite Acquisition to enable EOR projects, as well as capacity to allow for potential further field development opportunities;
- the timing and success of the Villeperdue West development project, including drilling and related production rates as well as future phases of the Vert La Gravelle redevelopment project, and other organic growth opportunities in France;
- future development potential of Triassic reservoirs in France and the ability to maintain current and forecast production in France;
- the ability of IPC to achieve and maintain current and forecast production in Malaysia and the ability to identify, mature and drill additional infill drilling locations;
- estimates of reserves;
- estimates of contingent resources;
- the ability to generate free cash flows and use that cash to repay debt; and
- future drilling and other exploration and development activities.

Statements relating to "reserves" and "contingent resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. 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 fluctuations, including those experienced in 2020;
- exchange rate and 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, 2019 (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.

Reserve estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets in Canada (including oil and gas assets acquired in the Granite Acquisition) are effective as of December 31, 2019, and are included in the reports prepared by Sproule Associates Limited (Sproule), 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 Sproule's December 31, 2019 price forecasts.

Reserve estimates, contingent 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, 2019, 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 Sproule's December 31, 2019 price forecasts.

The price forecasts used in the Sproule and ERCE reports are available on the website of Sproule (sproule.com) and are contained in the AIF. These price forecasts are as at December 31, 2019 and may not be reflective of current and future forecast commodity prices.

2P reserves as at December 31, 2019 of 300 MMboe includes 286.2 MMboe attributable to IPC's oil and gas assets and 14.0 MMboe attributable to oil and gas assets acquired in the Granite Acquisition. Contingent resources (best estimate, unrisked) as at December 31, 2019 of 1,089 MMboe includes 1,082.5 MMboe attributable to IPC's oil and gas assets and 6.2 MMboe attributable to oil and gas assets acquired in the Granite Acquisition. The reserve life index (RLI) is calculated by dividing the 2P reserves of 300 MMboe as at December 31, 2019 (including the 2P reserves attributable to oil and gas assets acquired in the Granite Acquisition), by the mid-point of the 2020 CMD production guidance of 46,000 to 50,000 boepd.

The product types comprising the 2P reserves described in this MD&A are contained in the AIF. 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.

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.

2P reserves and contingent resources included in the reports prepared by Sproule and ERCE in respect of IPC's oil and gas assets in Canada, France and Malaysia have been aggregated by IPC and may also be aggregated by IPC with the 2P reserves and contingent resources attributable to the oil and gas assets acquired in the Granite Acquisition included in the reports prepared by Sproule on behalf of 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".

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
MMbtu	Million British thermal units
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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