Q2

International Petroleum Corporation

Management's Discussion and Analysis

For the three and six months ended June 30, 2026

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

Forward-Looking Statements
Certain statements contained in this MD&A constitute “forward-looking statements” or “forward-looking information” (within the meaning of applicable securities legislation). Such statements and information (together, “forward-looking statements”) relate to future events, including the Corporation’s future performance, business prospects or opportunities. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as “seek“, “anticipate“, “plan“, “continue“, “estimate“, “expect“, “may“, “will“, “project“, “forecast“, “predict“, “potential“, “targeting“, “intend“, “could“, “might“, “should“, “believe“, “budget“ and similar expressions) are not statements of historical fact and may be “forward-looking statements“. Although IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. For additional information underlying forward-looking statements, refer to the “Cautionary Statement Regarding Forward-Looking Information” on page 24.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in Canada and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERC Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule ERCE’s December 31, 2025, price forecasts.

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

INTRODUCTION

This management's discussion and analysis ("MD&A") for International Petroleum Corporation ("IPC" or the "Corporation" and, together with its subsidiaries, the "Group") is dated August 4, 2026 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 for the three and six months ended June 30, 2026 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2025 ("Financial Statements").

Group Overview
The Group is in the business of 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.

The Corporation's common shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden. The Corporation is incorporated and domiciled in British Columbia, Canada, under the Business Corporations Act. The address of its registered office is Suite 3500, 1133 Melville Street, Vancouver, BC V6E 4E5, Canada and its business address is Suite 2800, 1055 Dunsmuir Street, Vancouver, BC V7X 1L2, Canada.

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

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

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

	Six months ended June 30, 2026		Six months ended June 30, 2025		Twelve months ended December 31, 2025	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1670	1.1394	1.0930	1.1720	1.1293	1.1750
1 USD equals CAD	1.3780	1.4236	1.4102	1.3675	1.3975	1.3692
1 USD equals MYR	3.9802	4.0850	4.3772	4.2120	4.2791	4.0580

HIGHLIGHTS

Q2 2026 Business Highlights

- Average net production of approximately 42,200 barrels of oil equivalent per day (boepd) for the second quarter of 2026, in line with guidance for the period (53% heavy crude oil, 13% light and medium crude oil and 34% natural gas).[1]
- Blackrod Phase 1 first oil achieved in May 2026, ahead of schedule and on budget.
- Following the increase in commodity prices, oil drilling in France commenced in the second quarter, with the first well online and delivering initial results ahead of expectations.

Q2 2026 Financial Highlights

- Operating costs per boe of USD 19.1 for Q2 2026, in line with guidance.[3]
- Operating cash flow (OCF) generation of MUSD 67 for Q2 2026.[3]
- Capital and decommissioning expenditures of MUSD 49 for Q2 2026, in line with guidance.
- Free cash flow (FCF) generation for Q2 2026 amounted to MUSD 4.[3]
- Net result of MUSD 10 for Q2 2026.
- Increased the Canadian revolving credit facility to MCAD 348.5 (approximately MUSD 250), and extended the maturity to May 2028.

Reserves and Resources

- Total 2P reserves as at December 31, 2025 of 521 MMboe, with a reserve life index (RLI) of 31 years.[1][2]
- Contingent resources (best estimate, unrisked) as at December 31, 2025 of 1,224 MMboe.[1][2]

2026 Annual Guidance

- Full year 2026 average net production guidance range maintained at 44,000 to 47,000 boepd.[1]
- Full year 2026 operating costs guidance range maintained at USD 18 to 20 per boe.[3]
- Full year 2026 OCF revised guidance estimated at between MUSD 230 and 330 (assuming Brent USD 70 to 90 per barrel for the remainder of 2026) from previous guidance of between MUSD 220 and 340 (assuming Brent USD 70 to 90 per barrel).[3][4]
- Full year 2026 capital and decommissioning expenditures guidance forecast maintained at MUSD 163.
- Full year 2026 FCF revised guidance estimated at between MUSD 10 and 110 (assuming Brent USD 70 to 90 per barrel for the remainder of 2026) from previous guidance of between MUSD 0 and 120 (assuming Brent USD 70 to 90 per barrel).[3][4]

	Three months ended June 30		Six months ended June 30	
USD Thousands	2026	2025	2026	2025
Revenue	185,738	158,892	358,748	337,384
Gross profit	38,094	23,663	75,269	67,812
Net result	9,917	13,850	22,679	30,081
Operating cash flow[3]	66,518	54,873	134,253	129,663
Free cash flow[3]	3,895	(58,252)	(13,191)	(101,424)
EBITDA[3]	63,856	51,519	128,145	122,465
Net cash/(debt)[3]	(508,999)	(374,977)	(508,999)	(374,977)

OPERATIONS REVIEW

Business Overview

Oil prices continued to strengthen through the second quarter of 2026 due to the on-going geopolitical tensions and constrained product flows through the Strait of Hormuz. Market volatility remains high in anticipation of a lasting ceasefire and resolution of the conflict in Iran ahead of the US mid-term elections. The International Energy Agency member countries' strategic reserves release (SPR) is progressing as planned to combat the unprecedented supply disruption, with nearly 75% of the targeted 400 million barrel release complete. In addition to the global storage release, China has reduced petroleum imports by one-third, or by approximately 4 million barrels per day, with reduced refinery runs. Market commentators question how long these reduced runs can be sustained. In combination with depleting spare capacity, the physical backdrop for the crude market remains tight and supported by the enhanced importance of energy security. As at the end of the second quarter, IPC's West Texas Intermediate (WTI) and Brent hedges have rolled off, and IPC is now fully exposed to these benchmark oil prices for the second half of 2026 and onward.

The second quarter 2026 WTI to Western Canadian Select (WCS) price differential averaged approximately USD 15 per barrel. The differential remains sensitive to refinery demand for heavy crude on the US Gulf Coast and the availability of competing heavy crude supplies, which also is partially impacted in the short term by US SPR releases. IPC is well-positioned to mitigate the partial differential increase with 2026 full year WTI to WCS differential hedges for 5,000 barrels per day at USD -12.50 per barrel. In addition, IPC has hedged from July 2026 to December 2027, 5,000 barrels per day and from January 2027 to December 2027, a further 5,000 barrels per day of the differential between the WCS price in Hardisty, Canada and the WCS price in Houston, USA, effectively hedging the transportation cost between the locations, at USD -7.55 per barrel and USD -7.50 per barrel, respectively. In addition, 2,000 barrels per day of quality differential between the WCS in Houston and the WTI are hedged from July to December 2026 at USD -3.65 per barrel.

The average Canadian gas benchmark price, AECO, was CAD 1.61 per Mcf for the second quarter of 2026, with Western Canadian Sedimentary Basin (WCSB) natural gas inventory levels remaining above historical averages. Market sentiment improved during the quarter as LNG Canada ramped up and Alberta data centre plans were announced which should increase regional demand and provide support for Canadian gas prices in the future. IPC has implemented hedges for 15,000 GJ (approximately 14,500 Mcf) per day at CAD 2.73 per GJ (approximately CAD 2.84 per Mcf) for 2026 from April to October 2026.

Second Quarter 2026 Highlights and Full Year 2026 Guidance

During the second quarter of 2026, IPC's portfolio delivered average net production of 42,200 boepd, in line with the guidance for the quarter. Operational performance from the producing assets was strong as high facility and well uptimes were achieved. IPC maintains the full year 2026 average net production guidance range of 44,000 to 47,000 boepd.(1)

IPC's operating costs per boe for the second quarter of 2026 were USD 19.1, in line with guidance. Full year 2026 operating expenditure guidance of USD 18.0 to 20.0 per boe remains unchanged.(3)

Operating cash flow (OCF) generation for the second quarter of 2026 was USD 67 million. Full year 2026 OCF guidance is tightened to USD 230 to 330 million (assuming Brent USD 70 to 90 per barrel for the remainder of 2026).(3)(4)

Capital and decommissioning expenditure for the second quarter of 2026 was USD 49 million in line with guidance. Full year 2026 capital and decommissioning expenditure is maintained at USD 163 million.

Free cash flow (FCF) generation was USD 4 million during the second quarter of 2026. Full year 2026 FCF guidance is tightened to USD 10 to 110 million (assuming Brent USD 70 to 90 per barrel for the remainder of 2026).(3)(4)

As at June 30, 2026, IPC's net debt position was USD 509 million, from a net debt position of USD 513 million as at March 31, 2026.

As previously announced, in April 2026, IPC increased the facility size of its Canadian credit facility to CAD 348.5 million (approximately USD 250 million) and extended the maturity of the facility to May 2028. IPC also previously announced the 2025 refinancing of its USD 450 million of unsecured bonds, with maturity in October 2030. This strong liquidity position, combined with the better than forecast cash flow generation to date and forecast for 2026, supports IPC in following through on its key strategic objectives to maximize stakeholder value.

IPC maintains the ability to repurchase up to approximately 6.5 million common shares up to early December 2026 under the renewed normal course issuer bid (NCIB) announced in Q4 2025. IPC has not purchased any common shares under the 2025/2026 NCIB to date. As at June 30, 2026 and August 4, 2026, IPC had a total of 112,826,752 common shares issued and outstanding and IPC held no common shares in treasury.

Blackrod

The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. After more than a decade of pilot operations, subsurface delineation and commercial engineering studies, IPC sanctioned the Phase 1 steam-assisted gravity drainage (SAGD) development in the first quarter of 2023. The Phase 1 development targets 311 MMboe of 2P reserves. As previously announced, first oil at the Blackrod Phase 1 project was achieved at the end of May 2026, ahead of schedule and on budget. The production ramp up continues in Q3 2026 and is expected to build inventories at the central processing facility (CPF) and at the batching station where oil will subsequently be shipped on the Grand Rapids Pipeline to be sold at Edmonton. More significant production and sales volumes from Blackrod Phase 1 are expected in Q4 2026, in line with IPC's annual production guidance. The forecast plateau production of 30,000 bopd is still expected to be achieved by the end of 2027.(1)(2)

By the end of the second quarter of 2026, the final cumulative growth capital of approximately USD 855 million has been spent on the Blackrod Phase 1 development since sanction. Construction at the CPF and well pad facilities were completed, commissioning activities are substantially complete in line with schedule, and drilling plus completions have been completed in line with plan. Site health and safety control has been excellent with no lost time incidents since commercial development activities commenced.

The total growth capital expenditure of USD 855 million comprises the total installed costs for the facilities and associated 40 well pairs needed to fill the plant capacity of 30,000 bopd and has remained unchanged since the time of sanction in 2023.(1)

Blackrod is a multi-generational asset that is being unlocked through the first phase of commercial development. More than 1.45 billion barrels of recoverable resource lies within the contiguous reservoir wholly owned by IPC. Future facilities expansion and phase development concepts continue to be matured by IPC. Blackrod has regulatory approval for up to 80,000 bopd.(1)(2)

Environmental, Social and Governance (ESG) Performance

Alongside the publication of the second quarter 2026 financial report, IPC releases its annual Sustainability Report. The Sustainability Report provides details on IPC's approach to sustainability and material sustainability topics highlighting specific initiatives and progress. The Sustainability Report is available on IPC's website at www.international-petroleum.com.

During the second quarter of 2026, IPC recorded no material safety or environmental incidents. IPC sadly reports that a tragic incident occurred at end July 2026 at one of IPC's operational sites in France where a contractor lost his life. The causes of the accident remain under investigation. IPC's sincere condolences are to the deceased individual's family and to all those affected by this accident. IPC confirms its ongoing commitment to the health and safety of all personnel.

Notes:

(1) See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory" below. See also the annual information form for the year ended December 31, 2025 (AIF) available on IPC's website at www.international-petroleum.com and under IPC's profile on SEDAR+ at www.sedarplus.ca.

(2) See "Reserves and Resources Advisory" below. Further information with respect to IPC's reserves, contingent resources and estimates of future net revenue are described in the AIF.

(3) Non-IFRS measures, see "Non-IFRS Measures" below.

(4) OCF and FCF forecasts at Brent USD 70 to 90 per barrel assume Brent to WTI differential of USD 5 per barrel and WTI to WCS differential of USD 14 per barrel for the remainder of 2026. OCF and FCF forecasts assume gas price on average of approximately CAD 1.88 per Mcf for the remainder of 2026.

Operations Overview

Q2 2026 Overview

In Q2 2026, IPC continued to successfully demonstrate its commitment to operational excellence, delivering production performance and operating expenditure in line with IPC's latest guidance. No material safety or environmental incidents were recorded in the quarter.

At the end of Q1 2026, as a result of the improved pricing environment and the strong operational performance year to date, IPC increased the 2026 capital expenditure budget to allow additional production well drilling activities in France and Canada. As of the end of Q2 2026, two of the four planned sidetrack wells in France have been drilled. The first Fontaine-au-Bron field well was brought online in June with initial production performance ahead of expectations. In Canada, drilling of four additional oil production wells in the Suffield Area Basal Quartz formation has commenced and is scheduled to continue through the second half of 2026.

At the Blackrod Phase 1 development, first oil was achieved in May 2026, on budget and ahead of schedule. At the end of Q2 2026, construction at the Central Processing Facility (CPF) and well pad facilities were completed, and commissioning activities are substantially complete in line with schedule. A total of five well pairs were converted to steam-assisted gravity drainage (SAGD) production in the quarter, with initial production results in line with expectations. Another 25 well pairs continue the production and injection well pair warm-up process, through steam circulation. An additional 10 well pairs are expected to be brought onto steam circulation by the end of Q3 2026.

Reserves and Resources

The total 2P reserves attributable to IPC's oil and gas assets are 521 MMboe as at December 31, 2025, as certified by IPC's independent third-party reserve auditor and evaluator. The 2P reserve life index (RLI) as at December 31, 2025, is approximately 31 years. Best estimate contingent resources as at December 31, 2025, are 1,224 MMboe (unrisked). See "Reserves and Resources Advisory" below.

Production

Average daily net production for Q2 2026 was in line with IPC's latest guidance at 42,200 boepd with stable operational performance in all regions.

With strong operational delivery year-to-date, and a phased ramp-up of production at Blackrod Phase 1 through the second half of 2026, IPC remains well positioned to deliver an annual net average daily production within the guidance range of 44,000 to 47,000 boepd.

The production during Q2 and the first six months of 2026 with comparatives is summarized below:

Production in Mboepd	Three months ended June 30		Six months ended June 30		Year ended December 31
	2026	2025	2026	2025	2025
Crude oil					
Canada – Northern Assets	14.5	13.6	14.4	13.8	14.7
Canada – Southern Assets	8.9	10.4	9.0	10.6	10.2
Malaysia	2.9	2.4	3.1	2.6	3.0
France	1.8	2.2	1.9	2.2	2.1
Total crude oil production	**28.1**	28.6	**28.4**	29.2	30.0
Gas					
Canada – Northern Assets	0.4	0.4	0.4	0.4	0.4
Canada – Southern Assets	13.7	14.6	13.8	14.4	14.5
Total gas production	**14.1**	15.0	**14.2**	14.8	14.9
Total production	**42.2**	43.6	**42.6**	44.0	44.9
Quantity in MMboe	**3.84**	3.97	**7.71**	7.97	16.38

See "Supplemental Information regarding Product Types" in "Reserves and Resources Advisory".

CANADA

Production in Mboepd	Working Interest (WI)	Three months ended June 30		Six months ended June 30		Year ended December 31
		2026	2025	**2026**	2025	**2025**
- Oil Onion Lake Thermal	100%	11.4	11.4	11.6	11.4	12.2
- Oil Suffield Area	100%	8.0	9.1	8.1	9.2	8.9
- Oil Other	50-100%	4.0	3.5	3.7	3.8	3.8
- Gas	~100%	14.1	15.0	14.2	14.8	14.9
Canada		**37.5**	39.0	**37.6**	39.2	39.8

Production
Net production from IPC's assets in Canada during Q2 2026 was in line with guidance at 37.5 Mboepd with stable operational performance at the major oil and gas producing assets.

Organic Growth and Capital Projects
As of the end of Q2 2026, budgeted development activity in Canada continues to progress in line with plan.

At the Suffield Area, drilling in the Basal Quartz formation has recommenced with an additional four production wells to be drilled in the second half of 2026.

At Onion Lake Thermal, IPC continues to work to mature the potential next phase of infill well targets and progress study work to optimize future sustaining well pad targets and locations.

At Blackrod Phase 1, construction activities are complete and commissioning activities were substantially complete in line with schedule by the end of Q2 2026. The production and injection well pair warm-up process, through steam circulation, continued through the quarter, with first oil achieved in May 2026. A total of five well pairs were converted by the end of Q2 2026. Initial production is in line with expectations, with production rates expected to increase through the second half of 2026. Forecast plateau production of 30,000 bopd is expected to be achieved by the end of 2027.

MALAYSIA

Production in Mboepd	WI	Three months ended June 30		Six months ended June 30		Year ended December 31
		2026	2025	**2026**	2025	2025
Bertam	100%	**2.9**	2.4	**3.1**	2.6	3.0

Production
Net production in Malaysia during Q2 2026 was in line with guidance at 2.9 Mboepd.

Operational Projects
Planned well maintenance at the Bertam field was completed on schedule and budget in early Q3 2026.

FRANCE

Production in Mboepd	WI	Three months ended June 30		Six months ended June 30		Year ended December 31
		2026	2025	**2026**	2025	**2025**
France	35–100%[1]	**1.8**	2.2	**1.9**	2.2	2.1

[1] *In Q2 2026, IPC entered into an asset exchange agreement relating to certain fields in the Paris Basin and the Aquitaine Basin. Completion of the asset exchange remains subject to regulatory approval.*

Production
Net production in France during Q2 2026 was in line with guidance at 1.8 Mboepd.

Organic Growth
In France, the planned drilling operations of three sidetrack wells at the Fontaine-au-Bron field and one sidetrack well at the Villeperdue field commenced in Q2 2026. By the end of Q2 2026, two of four sidetrack wells have been successfully drilled. The first Fontaine-au-Bron well was brought online in June with initial production performance ahead of expectations.

FINANCIAL REVIEW

Financial Results

Selected Annual Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q2-26	Q1-26	Q4-25	Q3-25	Q2-25	Q1-25	Q4-24	Q3-24
Revenue	**185,738**	173,010	176,207	172,297	158,892	178,492	199,124	173,200
Gross profit	**38,094**	37,175	28,242	32,066	23,663	44,149	42,774	39,505
Net result	**9,917**	12,762	(4,942)	3,802	13,850	16,231	415	22,875
Earnings per share – USD	**0.09**	0.11	(0.04)	0.03	0.12	0.14	0.00	0.19
Earnings per share fully diluted – USD	**0.09**	0.11	(0.04)	0.03	0.12	0.13	0.00	0.18
Operating cash flow[1]	**66,518**	67,735	63,138	66,102	54,873	74,790	78,158	72,589
Free cash flow[1]	**3,895**	(17,086)	(28,627)	(23,083)	(58,252)	(43,172)	(61,476)	(38,269)
EBITDA[1]	**63,856**	64,289	58,966	62,106	51,519	70,946	76,184	68,313
Net cash/(debt) at period end[1]	**(508,999)**	(513,413)	(483,615)	(434,822)	(374,977)	(314,255)	(208,528)	(157,228)

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	June 30, 2026	December 31, 2025
Non-current assets	1,839,184	1,847,327
Current assets	171,151	130,302
Total assets	**2,010,335**	1,977,629
Total non-current liabilities	924,243	890,204
Current liabilities	177,277	160,248
Total liabilities	**1,101,520**	1,050,452
Net assets	**908,815**	927,177
Working capital (including cash)	**(6,126)**	(29,946)

Selected Interim Financial 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 and Blackrod assets) and (ii) Canada – Southern Assets (comprised mainly of the Suffield area assets). This is consistent with the internal reporting provided to the CEO, who is the chief operating decision maker. The following tables present certain segment information.

	Three months ended June 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	128,275	70,508	22,521	17,036	–	**238,340**
NGLs	–	240	–	–	–	**240**
Gas	71	8,673	–	–	–	**8,744**
Net sales of oil and gas	**128,346**	**79,421**	**22,521**	**17,036**	–	**247,324**
Royalties	(19,809)	(11,516)	–	(1,035)	–	**(32,360)**
Hedging settlement	(18,917)	(10,650)	–	–	–	**(29,567)**
Other operating revenue	–	–	–	162	179	**341**
Revenue	**89,620**	**57,255**	**22,521**	**16,163**	**179**	**185,738**
Operating costs	(21,734)	(27,993)	(15,318)	(8,393)	–	**(73,438)**
Cost of blending	(40,912)	(6,652)	–	–	–	**(47,564)**
Change in inventory position	572	(234)	2,693	(200)	–	**2,831**
Depletion	(9,064)	(11,620)	(5,442)	(2,676)	–	**(28,802)**
Exploration and business development costs	–	–	–	–	(671)	**(671)**
Gross profit/(loss)	**18,482**	**10,756**	**4,454**	**4,894**	**(492)**	**38,094**

	Three months ended June 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	85,933	54,069	11,828	11,463	–	163,293
NGLs	–	167	–	–	–	167
Gas	72	9,680	–	–	–	9,752
Net sales of oil and gas	86,005	63,916	11,828	11,463	–	173,212
Change in under/over lift position	–	–	–	1,559	–	1,559
Royalties	(11,932)	(8,953)	–	(732)	–	(21,617)
Hedging settlement	2,236	3,139	–	–	–	5,375
Other operating revenue	–	–	–	205	158	363
Revenue	76,309	58,102	11,828	12,495	158	158,892
Operating costs	(19,786)	(30,500)	(11,768)	(8,468)	–	(70,522)
Cost of blending	(27,286)	(5,983)	–	–	–	(33,269)
Change in inventory position	(695)	380	203	(7)	–	(119)
Depletion	(8,885)	(12,652)	(4,891)	(2,893)	–	(29,321)
Depreciation of other assets	–	–	(1,461)	–	–	(1,461)
Exploration and business development costs	–	–	–	–	(537)	(537)
Gross profit/(loss)	19,657	9,347	(6,089)	1,127	(379)	23,663

USD Thousands	Six months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	226,026	121,592	47,081	37,672	–	**432,371**
NGLs	–	383	–	–	–	**383**
Gas	165	20,921	–	–	–	**21,086**
Net sales of oil and gas	**226,191**	**142,896**	**47,081**	**37,672**	–	**453,840**
Change in under/over lift position	–	–	–	(4,744)	–	**(4,744)**
Royalties	(32,009)	(17,294)	–	(1,733)	–	**(51,036)**
Hedging settlement	(25,192)	(14,665)	–	–	–	**(39,857)**
Other operating revenue	–	–	–	366	179	**545**
Revenue	**168,990**	**110,937**	**47,081**	**31,561**	**179**	**358,748**
Operating costs	(41,101)	(57,846)	(24,441)	(18,289)	–	**(141,677)**
Cost of blending	(74,605)	(11,850)	–	–	–	**(86,455)**
Change in inventory position	863	14	4,024	59	–	**4,960**
Depletion	(17,885)	(23,393)	(11,567)	(5,888)	–	**(58,733)**
Exploration and business development costs	–	–	–	–	(1,574)	**(1,574)**
Gross profit/(loss)	**36,262**	**17,862**	**15,097**	**7,443**	**(1,395)**	**75,269**

USD Thousands	Six months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	184,169	117,855	27,204	24,277	–	353,505
NGLs	–	358	–	–	–	358
Gas	179	21,195	–	–	–	21,374
Net sales of oil and gas	184,348	139,408	27,204	24,277	–	375,237
Change in under/over lift position	–	–	–	2,700	–	2,700
Royalties	(25,052)	(18,621)	–	(1,572)	–	(45,245)
Hedging settlement	1,393	2,766	–	–	–	4,159
Other operating revenue	–	–	–	375	158	533
Revenue	160,689	123,553	27,204	25,780	158	337,384
Operating costs	(38,966)	(63,825)	(20,349)	(16,535)	–	(139,675)
Cost of blending	(59,677)	(11,318)	–	–	–	(70,995)
Change in inventory position	169	(156)	3,542	(174)	–	3,381
Depletion	(17,682)	(24,954)	(10,642)	(5,059)	–	(58,337)
Depreciation of other assets	–	–	(3,378)	–	–	(3,378)
Exploration and business development costs	–	–	–	–	(568)	(568)
Gross profit/(loss)	44,533	23,300	(3,623)	4,012	(410)	67,812

Three and six months ended June 30, 2026 Review

Revenue

Total revenue amounted to USD 185,738 thousand for Q2 2026, compared to USD 158,892 thousand for Q2 2025 and USD 358,748 thousand for the first six months of 2026 compared to the 337,384 thousand for the first six months of 2025 is analyzed as follows:

	Three months ended June 30		Six months ended June 30	
USD Thousands	2026	2025	2026	2025
Crude oil sales	238,340	163,293	432,371	353,505
Gas and NGL sales	8,984	9,919	21,469	21,732
Change in under/overlift position	–	1,559	(4,744)	2,700
Royalties	(32,360)	(21,617)	(51,036)	(45,245)
Hedging settlement	(29,567)	5,375	(39,857)	4,159
Other operating revenue	341	363	545	533
Revenue	**185,738**	158,892	**358,748**	337,384

The main components of revenue for the three and six months ended June 30, 2026 and June 30, 2025, respectively, are detailed below.

Crude oil sales

	Three months ended June 30, 2026				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	128,275	70,508	22,521	17,036	**238,340**
- Quantity sold in bbls	1,660,902	890,100	217,125	168,480	**2,936,607**
- Average price realized USD per bbl	77.23	79.21	103.72	101.12	**81.16**

	Three months ended June 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	85,933	54,069	11,828	11,463	163,293
- Quantity sold in bbls	1,614,538	1,010,851	175,829	167,394	2,968,612
- Average price realized USD per bbl	53.22	53.49	67.27	68.49	55.01

Crude oil revenue was 46% higher in Q2 2026 compared to Q2 2025 mainly due to higher oil prices.

The Suffield area assets, Onion Lake Thermal and Blackrod 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 2026, WTI averaged USD 92 per bbl compared to USD 64 per bbl for Q2 2025 and the average discount to WCS used in IPC's pricing formula was USD 15 per bbl compared to USD 10 per bbl for the comparative period in 2025.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices. There was one cargo lifting in Malaysia during Q2 2026 and one cargo lifting in Q2 2025. Produced unsold oil barrels from Bertam at the end of Q2 2026 amounted to 140,000 bbls, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 104 per bbl for Q2 2026 compared to USD 68 per bbl for the comparative period.

USD Thousands	Six months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	226,026	121,592	47,081	37,672	**432,371**
- Quantity sold in bbls	3,377,276	1,776,342	440,218	447,666	**6,041,502**
- Average price realized USD per bbl	66.93	68.45	106.95	84.15	**71.57**

USD Thousands	Six months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	184,169	117,855	27,204	24,277	353,505
- Quantity sold in bbls	3,303,184	2,092,938	370,960	336,416	6,103,498
- Average price realized USD per bbl	55.75	56.31	73.33	72.17	57.92

The Suffield area assets, Onion Lake and Blackrod crude oil in Canada are 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.

Crude oil revenue was higher by 22% during the first six months of 2026 compared to the first six months of 2025 due to higher oil prices.

The Canadian realized sales price is based on the WCS price which trades at a discount to WTI. For the first six months of 2026, WTI averaged USD 82 per bbl compared to USD 68 per bbl for the comparative period and the average discount to WCS used in IPC's pricing formula was USD 14 per bbl compared to USD 11 per bbl for the comparative period.

The realized sales price for Malaysia and France is based on Dated Brent crude oil prices and the average market Brent crude oil price was USD 92 per bbl for the first six months of 2026 compared to USD 72 per bbl for the comparative period.

Gas and NGL sales

	Three months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	71	8,913	**8,984**
- Quantity sold in Mcf	69,170	6,832,876	**6,902,046**
- Average price realized USD per Mcf	1.03	1.30	**1.30**

	Three months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	72	9,847	9,919
- Quantity sold in Mcf	64,237	7,321,587	7,385,824
- Average price realized USD per Mcf	1.13	1.34	1.34

Gas and NGL sales revenue was 9% lower for the Q2 2026 compared to Q2 2025, mainly due to lower sales volumes and lower gas prices achieved.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q2 2026, IPC realized an average price of CAD 1.75 per Mcf compared to AECO average pricing of CAD 1.61 per Mcf.

	Six months ended June 30, 2026		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	164	21,305	**21,469**
- Quantity sold in Mcf	140,459	13,524,186	**13,664,645**
- Average price realized USD per Mcf	1.17	1.58	**1.57**

	Six months ended June 30, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	179	21,553	21,732
- Quantity sold in Mcf	143,072	14,207,432	14,350,504
- Average price realized USD per Mcf	1.25	1.52	1.51

Gas and NGL sales revenue was 1% lower for the first six months of 2026 compared to the first six months of 2025 mainly due to the lower production.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first six months of 2026, IPC realized an average price of CAD 2.13 per Mcf compared to AECO average pricing of CAD 1.80 per Mcf.

Hedging settlement
IPC enters into oil and gas prices risk management contracts in order to ensure a certain level of cash flow. It focuses mainly on oil and gas price swaps and on collars to a lesser extent, to mitigate these commodities price exposure. Oil and gas hedging contracts are not entered into for speculative purposes and only account for a portion of IPC's production.

The realized hedging settlement for the first six months of 2026 amounted to a loss of USD 39,857 thousand and consisted of a loss of USD 41,035 thousand on the oil contracts and a gain of USD 1,178 thousand on the gas contracts. Also see the Financial Position and Liquidity and the Financial Risk Management sections below.

Production costs
Production costs including inventory movements amounted to USD 118,171 thousand for Q2 2026 compared to USD 103,910 thousand for Q2 2025 and USD 223,172 thousand for the first six months of 2026 compared to the 207,289 thousand for the first six months of 2025, and is analyzed as follows:

	Three months ended June 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	21,734	27,993	15,318	8,393	–	**73,438**
USD/boe[2]	16.07	13.63	57.26	50.50	n/a	**19.12**
Cost of blending	40,912	6,652	–	–	–	**47,564**
Change in inventory position	(572)	234	(2,693)	200	–	**(2,831)**
Production costs	**62,074**	**34,879**	**12,625**	**8,593**	–	**118,171**

	Three months ended June 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	19,786	30,500	12,075	8,468	(307)	70,522
USD/boe[2]	15.47	13.42	55.10	42.40	n/a	17.76
Cost of blending	27,286	5,983	–	–	–	33,269
Change in inventory position	696	(380)	(203)	7	–	119
Production costs	47,767	36,103	11,872	8,475	(307)	103,910

USD Thousands	Six months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	41,101	57,846	24,441	18,289	–	**141,677**
USD/boe[2]	15.35	14.04	42.98	53.53	n/a	**18.38**
Cost of blending	74,605	11,850	–	–	–	**86,455**
Change in inventory position	(863)	(14)	(4,024)	(59)	–	**(4,960)**
Production costs	**114,843**	**69,682**	**20,417**	**18,230**	–	**223,172**

USD Thousands	Six months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	38,966	63,825	23,877	16,535	(3,528)	139,675
USD/boe[2]	15.14	14.09	50.08	42.73	n/a	17.53
Cost of blending	59,677	11,318	–	–	–	70,995
Change in inventory position	(169)	156	(3,542)	174	–	(3,381)
Production costs	98,474	75,299	20,335	16,709	(3,528)	207,289

[1] See definition on page 18 under "Non-IFRS measures".
[2] USD/boe in the tables above is calculated by dividing the cost by the production volume for each country for the period and for 2025.
[3] Included in the Malaysia operating costs to Q2 2025 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 costs per boe for Malaysia to USD 53.70 for Q2 2025 and 19.56 for the six months ended June 30, 2025.

Operating costs
Operating costs amounted to USD 73,438 thousand for Q2 2026 compared to USD 70,522 thousand for Q2 2025. Operating costs per boe amounted to USD 19.12 per boe in Q2 2026 slightly below the guidance for the quarter and compared with USD 17.76 per boe in Q2 2025.

Operating costs per boe in Malaysia increased in Q2 2026 compared to Q2 2025 due to lower production.

Cost of blending
For the Suffield area, Onion Lake Thermal and Blackrod assets in Canada, oil production is blended with purchased diluent to meet pipeline specifications. As a result of the blending, actual sales volumes are higher than produced barrels and the realized sales price of a blended barrel is higher than an unblended barrel.

The cost of the diluent amounted to USD 47,564 thousand for Q2 2026 compared to USD 33,269 thousand for Q2 2025 due to higher prices.

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. At the end of Q2 2026, IPC had crude entitlement of 140,000 bbls of oil on the FPSO Bertam facility being crude produced but not yet sold.

Depletion costs
The total depletion of oil and gas properties amounted to USD 28,802 thousand for Q2 2026 compared to USD 29,321 thousand for Q2 2025.

The depletion charge is analyzed in the following tables:

USD Thousands	Three months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	9,064	11,620	5,442	2,676	**28,802**
USD per boe[1]	6.70	5.66	20.34	16.10	**7.50**

USD Thousands	Three months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	8,885	12,652	4,891	2,893	29,321
USD per boe[1]	6.95	5.57	22.32	14.48	7.38

USD Thousands	Six months ended June 30, 2026 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	17,885	23,393	11,567	5,888	**58,733**
USD per boe[1]	6.68	5.68	20.34	17.23	**7.62**

USD Thousands	Six months ended June 30, 2025 Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	17,682	24,954	10,642	5,059	58,337
USD per boe[1]	6.87	5.51	22.32	13.07	7.32

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

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 tangible fixed assets
The total depreciation of other tangible fixed assets amounted to nil for Q2 2026 compared to USD 1,461 thousand for Q2 2025. In 2025, the depreciation relates to FPSO Bertam, which has been depreciated to its residual value by the end of 2025.

Exploration and business development costs
The total exploration and business development costs amounted to a cost of USD 1,574 thousand for the first six months of 2026 and USD 568 thousand for the first six months of 2025.

Net financial items
Net financial items amounted to a charge of USD 22,385 thousand for Q2 2026, compared to a gain of USD 159 thousand for Q2 2025, and a charge of USD 43,122 thousand for the first six months of 2026 compared to a charge of USD 18,696 thousand for the first six months of 2025, and included no realized currency hedge loss and a net foreign exchange loss of USD 13,752 thousand for the first six months of 2026 and compared to a realized currency hedge loss and a net foreign exchange gain of respectively USD 7,518 thousand and USD 14,233 thousand for the first six months of 2025. The foreign exchange movements are mainly resulting from the revaluation of intra-group loan funding balances.

Excluding foreign exchange movements and realized currency cashflow hedges, the net financial items amounted to a charge of USD 14,901 thousand for Q2 2026, compared to a charge of USD 13,396 thousand for Q2 2025 and a charge of USD 29,370 thousand for the first six months of 2026 compared to a charge of USD 25,411 thousand for the first six months of 2025.

The interest expense amounted to USD 10,051 thousand for Q2 2026, compared to USD 8,980 thousand for the comparative period in 2025 and USD 19,611 thousand for the first six months of 2026 compared to USD 17,741 thousand for the first six months of 2025, and mainly related to the bond interest at a fixed coupon rate of 7.5% per annum (former bonds in 2025 were bearing a fixed coupon rate of 7.25% per annum).

The unwinding of the asset retirement obligation discount rate amounted to USD 4,123 thousand for Q2 2026 compared to USD 4,115 thousand for Q2 2025 and USD 8,285 thousand for the first six months of 2026 compared to USD 8,072 thousand for the first six months of 2025.

Income tax
The corporate income tax amounted to a charge of USD 4,145 thousand for Q2 2026 compared to a charge of USD 6,167 thousand for Q2 2025 and a charge of USD 7,531 thousand for the first six months of 2026 compared to a charge of USD 10,846 thousand for the comparative period.

The current income tax amounted to a charge of USD 1,212 thousand for Q2 2026 and a charge of USD 1,668 thousand for the first six months of 2026 and mainly related to France. No corporate income tax is expected to be payable in Canada in 2026 due to the usage of historical tax pools.

Capital Expenditure

Development and exploration and evaluation expenditures incurred during the first six months of 2026 were as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	103,975	2,905	1,345	8,576	**116,801**
Exploration and evaluation	1,858	–	–	–	**1,858**
	105,833	2,905	1,345	8,576	**118,659**

Capital expenditures during the period were mainly spent in Canada on the Blackrod Phase 1 development project and in France on oil well drilling operations.

Other tangible fixed assets
Other tangible fixed assets amounted to USD 11,091 thousand as at June 30, 2026, which included USD 9,200 thousand in respect of the FPSO Bertam. The FPSO Bertam has been depreciated to its residual value.

Financial Position and Liquidity

Financing
As at January 1, 2025, IPC had USD 450 million of senior unsecured bonds outstanding, maturing in February 2027 with a fixed coupon rate of 7.25% per annum. In October 2025, IPC completed the issuance of USD 450 million of new senior unsecured bonds, maturing in October 2030 with a fixed coupon rate of 7.50% per annum, payable in semi-annual instalments in April and October, and with semi-annual amortizations of USD 25 million commencing in April 2028. The proceeds of the new bonds were used to fully redeem and cancel the previous bonds.

The bond repayment obligations as at June 30, 2026, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at June 30, 2026, the Group had a senior secured revolving credit facility of CAD 348.5 million (the "Canadian RCF") in connection with its oil and gas assets in Canada, with a maturity date in May 2028. As at June 30, 2026, CAD 100 million (approximately USD 70 million) was drawn under the Canadian RCF. As at June 30, 2026, the Group also had a letter of credit facility in Canada (the "LC Facility"). As at June 30, 2026, operational letters of credit in an aggregate of CAD 11.9 million have been issued under the LC Facility.

The Group is in compliance with the covenants of the bonds and its financing facilities as at June 30, 2026.

Net debt as at June 30, 2026 amounted to USD 509 million. Cash and cash equivalents held amounted to USD 11 million as at June 30, 2026.

IPC intends to fund remaining budgeted capital expenditures in 2026 with forecast cash flow generated by its operations, cash on hand and, if required, Canadian RCF loan drawing.

Working Capital
As at June 30, 2026, the Group had a working capital balance including cash of negative USD 6,126 thousand compared to negative USD 29,946 thousand as at December 31, 2025.

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"/"net cash", which are non-IFRS measures. Non-IFRS measures do not have any standardized meaning prescribed by IFRS and therefore may not 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 including net sales of diluent 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 decommissioning and farm-in expenditures less general and administrative 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 and business development costs, impairment costs and depreciation and before 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 and bonds less cash and cash equivalents. "Net cash" is calculated as cash and cash equivalents less bank loans and bonds.

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	**2026**	2025	**2026**	2025
Revenue	185,738	158,892	358,748	337,384
Production costs and net sales of diluent to third party[1]	(118,008)	(103,682)	(222,827)	(206,870)
Current tax	(1,212)	(337)	(1,668)	(851)
Operating cash flow	**66,518**	54,873	**134,253**	129,663

[1] *Includes net sales of diluent to third parties amounting to USD 345 thousand for the first six months of 2026.*

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	**2026**	2025	**2026**	2025
Operating cash flow - see above	66,518	54,873	134,253	129,663
Capital expenditures	(47,998)	(97,925)	(118,659)	(196,811)
Abandonment and farm-in expenditures[1]	(576)	(2,097)	(1,048)	(2,418)
General and administrative expenses before depreciation[2]	(3,874)	(3,691)	(7,776)	(8,049)
Cash financial items[3]	(10,175)	(9,412)	(19,961)	(23,809)
Free cash flow	**3,895**	(58,252)	**(13,191)**	(101,424)

[1] *See note 15 to the Financial Statements.*
[2] *Depreciation is not specifically disclosed in the Financial Statements.*
[3] *See note 4 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	2026	2025	2026	2025
Net result	9,917	13,850	22,679	30,081
Net financial items	22,385	(159)	43,122	18,696
Income tax	4,145	6,167	7,531	10,846
Depletion and decommissioning costs	28,802	29,321	58,733	58,337
Depreciation of other tangible fixed assets	–	1,461	–	3,378
Exploration and business development costs	671	537	1,574	568
Sale of assets[1]	(2,428)	(10)	(6,221)	(104)
Depreciation included in general and administrative expenses[2]	364	352	727	663
EBITDA	**63,856**	51,519	**128,145**	122,465

[1] Sale of assets is included under "Other income/(expense)" but not specifically disclosed in the Financial Statements.
[2] 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	2026	2025	2026	2025
Production costs	118,171	103,910	223,172	207,289
Cost of blending	(47,564)	(33,269)	(86,455)	(70,995)
Change in inventory position	2,831	(119)	4,960	3,381
Operating costs	**73,438**	70,522	**141,677**	139,675

Net cash/(debt)
The following table sets out how net cash/(debt) is calculated:

USD Thousands	June 30, 2026	December 31, 2025
Bank loans	(70,247)	(40,652)
Bonds	(450,000)	(450,000)
Cash and cash equivalents	11,248	7,037
Net cash/(debt)	**(508,999)**	(483,615)

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, had issued five letters of credit as at June 30, 2026 as follows: (a) MCAD 1.0 in respect of its obligations related to the Ferguson asset; (b) MCAD 1.3 in respect of pipeline access; (c) MCAD 0.5 in respect of the hedging of electricity prices; (d) MCAD 3.9 in respect of electricity distribution services; and (e) MCAD 5.3 in respect of the land acquisition completed in October 2025.

Outstanding Share Data

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

As at January 1, 2025, IPC had a total of 119,169,471 common shares issued and outstanding, of which 110,156 common shares were held in treasury.

Over the period of January 1, 2025 to December 4, 2025, IPC purchased and cancelled 6,641,970 common shares under the normal course issuer bid (NCIB) and 261,818 common shares under certain other exemptions in Canada.

As at December 31, 2025, IPC had a total of 112,155,527 common shares issued and outstanding, with no common shares held in treasury.

In February 2026, IPC issued 671,225 common shares in connection with the vesting of previously issued IPC Share Unit Plan awards. As at June 30, 2026 and August 4, 2026, IPC had a total of 112,826,752 common shares issued and outstanding, with no common shares held in treasury.

Nemesia S.à.r.l., an investment company ultimately controlled by trusts whose settlor is the late Adolf H. Lundin, holds 42,597,533 common shares in IPC, representing 37.8% of the outstanding common shares as at June 30, 2026.

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 2,575,515 IPC Share Unit Plan awards outstanding as at August 4, 2026 of which 794,243 awards were granted in 2026.

The Corporation is authorized to issue an unlimited number of common shares without par value. The Corporation is also authorized to issue an unlimited number of class A preferred shares and an unlimited number of class B preferred shares, issuable in series.

Contractual Obligations and Commitments

In the normal course of business, the Group has committed to certain payments which are not recognized as liabilities. The following table summarizes the Group's commitments in Canada as at June 30, 2026:

MCAD	2026	2027	2028	2029	2030	Thereafter
Transportation service[1]	30.4	83.8	99.5	100.8	101.7	1,355.0
Power[2]	6.2	12.4	9.8	–	–	–
Total commitments	**36.6**	**96.2**	**109.3**	**100.8**	**101.7**	**1,355.0**

[1] IPC has firm transportation commitments on oil and natural gas pipelines that expire between 2037 and 2046.
[2] IPC has physical delivery power hedges to purchase 15MWh at a weighted average price of CAD 74.92/MWh from July 1, 2026 to December 31, 2028, and an additional 5MWh at a weighted average price of CAD 58.31/MWh from July 1, 2026 to December 31, 2027.

Material 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.

Management believes the following critical accounting policies affect the more significant judgments and estimates used in the preparation of the consolidated financial statements:

Oil and gas reserves, impairment and asset retirement obligations

The accounting for oil and gas assets requires significant estimates and judgements, particularly in relation to reserves, impairment and asset retirement obligations. Estimates of proved and probable oil and gas reserves, prepared using standard recognized evaluation techniques and reviewed by independent qualified reserves auditors, are fundamental to impairment testing, depletion calculations under the unit of production method, and the timing and measurement of asset retirement obligations. These estimates are based on management's assumptions regarding expected production volumes, future oil and gas prices, development and production costs, and economic factors such as oil price and inflation.

Impairment tests are performed when there are indicators of impairment. Key assumptions in the impairment models include oil and gas reserve estimates, forward price curves, long-term cost assumptions and the discount rate, all of which are subject to change as new information becomes available or economic conditions evolve.

Provisions for asset retirement obligations are based on estimates of future decommissioning and restoration costs, reflecting current legal and constructive requirements, available technology and prevailing price levels. Actual cash outflows may differ from estimates due to changes in legislation, technical requirements or cost levels, and therefore these provisions are reviewed on a regular basis.

Deferred income tax assets

The Group accounts for differences that arise between the carrying amount of assets and liabilities and their tax bases in accordance with IAS 12, Income Taxes, which requires deferred income tax assets only to be recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Management estimates future taxable profits based on the financial models used to value its oil and gas properties. Any change to the estimates and assumptions used for the key operational and financial variables used within the business models could affect the amount of deferred income tax assets recognized.

The effects of changes in estimates do not give rise to prior year adjustments and are treated prospectively over the estimated remaining commercial reserves of each field. While the Group uses its best estimates and judgement, actual results could differ from these estimates.

Transactions with Related Parties

The Group recognizes the following related parties: associated companies, jointly controlled entities, key management personnel and members of their close family or other parties that are partly, directly or indirectly controlled by key management personnel or of its family or of any individual that controls, or has joint control or significant influence over the entity.

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.

During the first six months of 2026, the Group has not entered into material transactions with related parties.

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 risk as well as the risk related to the fluctuation in oil and gas prices. The Group seeks to control these risks through sound management practice and the use of internationally accepted financial instruments, such as oil and gas, condensate and electricity 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, 2026, the Group had entered into oil, gas and electricity 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 bonds or 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, 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 does not currently have any covenants under its current financing facilities to hedge future production.

The Group had oil price sale financial hedges outstanding as at June 30, 2026, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
July 1, 2026 - December 31, 2026	5,000	WTI/WCS Differential	USD -12.50/bbl
July 1, 2026 - December 31, 2027	5,000	WCS (Hardisty vs Houston)[1]	USD -7.55/bbl
July 1, 2026 - December 31, 2026	2,000	ARV[2]	USD -3.65/bbl

[1] Represents the cost of transporting a barrel of WCS quality from Hardisty, Alberta to Houston, Texas.
[2] Represents the difference in USD of a barrel of WCS quality in Houston against a barrel of WTI quality.

The Group had gas price sale financial hedges outstanding as at June 30, 2026, which are summarized as follows:

Period	Volume (Gigajoules (GJ) per day)	Type	Average Pricing
July 1, 2026 - October 31, 2026	15,000	AECO Swap	CAD 2.73/GJ

The Group had electricity financial hedges outstanding as at June 30, 2026, which are summarized as follows:

Period	Volume (MWh)	Type	Average Pricing
July 1, 2026 - September 30, 2040	3	AESO	CAD 75.00/MWh

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a positive fair value of USD 5,809 thousand as at June 30, 2026.

In July 2026, the Group entered into the following oil price sale financial hedge:

Period	Volume (barrels per day)	Type	Average Pricing
January 1, 2027 - December 31, 2027	5,000	WCS (Hardisty vs Houston)[1]	USD -7.50/bbl

[1] Represents the cost of transporting a barrel of WCS quality from Hardisty, Alberta to Houston, Texas.

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. There are currently no interest rate hedges.

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 FACTORS

IPC is engaged in the exploration, development and production of oil and gas and its operations are subject to various risks and uncertainties which include, but are not limited to, those listed below. For further information and discussion of these risks and uncertainties, please see IPC's Annual Information Form for the year ended December 31, 2025 ("AIF") available on SEDAR+ at www.sedarplus.ca or on IPC's website at www.international-petroleum.com. See also "Cautionary Statement Regarding Forward-Looking Information" and "Reserves and Resources Advisory" below.

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 Group's internal control over financial reporting during the three and six months ended June 30, 2026, 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). Management concluded that the Corporation's internal control over financial reporting was effective as of June 30, 2026.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

Forward-looking statements include, but are not limited to, statements with respect to:
- 2026 production ranges (including total daily average production), production composition, cash flows, 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 financial and operational flexibility to navigate the Corporation through periods of volatile commodity prices;
- The ability to fully fund IPC's future expenditures from cash flows and current borrowing capacity;
- IPC's intention and ability to continue to implement its 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;
- Development of the Blackrod project in Canada, including estimates of resource volumes, future production, timing, regulatory approvals, third party commercial arrangements, breakeven oil prices, net present values and future phase developments;
- Current and future production performance, operations and development potential of the Onion Lake Thermal, Suffield, Brooks, Ferguson and Mooney operations, including the timing and success of future oil and gas drilling and optimization programs;
- The potential improvement in the Canadian oil egress situation and IPC's ability to benefit from any such improvements;
- The ability of IPC to maintain current and forecast production in France and Malaysia;
- The intention and ability of IPC to acquire common shares under the NCIB, including the timing of any such purchases;
- The return of value to IPC's shareholders as a result of the NCIB;
- IPC's ability to implement its greenhouse gas (GHG) emissions intensity and climate strategies and to achieve its net GHG emissions intensity reduction targets;
- IPC's ability to implement projects to reduce net GHG emissions intensity, including potential carbon capture and storage;
- Estimates of reserves and contingent resources;
- The ability to generate free cash flows and use that cash to repay debt;
- IPC's continued access to its existing credit facilities, including current financial headroom, on terms acceptable to the Corporation;
- IPC's ability to identify and complete future acquisitions;
- Expectations regarding the oil and gas industry in Canada, Malaysia and France, including assumptions regarding future royalty rates, regulatory approvals, legislative changes, tariffs, and ongoing projects and their expected completion; 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 Resources Advisory".

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; 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; IPC's ability to maintain its existing credit ratings; IPC's ability to achieve its performance targets; 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 and that IPC will be able to implement its standards, controls, procedures and policies in respect of any acquisitions and realize the expected synergies on the anticipated timeline or at all; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; IPC's intention to complete share repurchases under the normal course issuer bid program, including the funding of such share repurchases, existing and future market conditions, including with respect to the price of IPC's common shares, and compliance with respect to applicable limitations under securities laws and regulations and stock exchange policies; 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: general global economic, market and business conditions; 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; interest rate and exchange rate fluctuations; marketing and transportation; loss of markets; environmental and climate-related risks; competition; innovation and cybersecurity risks related to IPC's systems, including costs of addressing or mitigating such risks; the ability to attract, engage and retain skilled employees; 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; geopolitical conflicts, including current and potential future conflicts in Ukraine, the Middle East, South America and elsewhere and their potential impact on, among other things, global market conditions; political or economic developments, including, without limitation, the risk that (i) the tariffs that are currently in effect on goods exported from or imported into Canada continue in effect for an extended period of time, the tariffs that have been threatened are implemented, that tariffs that are currently suspended are reactivated, the rate or scope of tariffs are increased, or new tariffs are imposed, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed or threatened to be imposed by the U.S. on other countries and retaliatory tariffs imposed or threatened to be imposed by other countries on the U.S. will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Corporation, including by decreasing demand for, and the price of oil, and natural gas, disrupting supply chains, increasing costs, causing volatility in the global financial markets, and limiting access to financing; 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. See also "Risk Factors".

Estimated production and FCF generation are based on IPC's current business plans over the periods of 2026 to 2030 and 2031 to 2035, less net debt of USD 484 million as at December 31, 2025, with assumptions based on the reports of IPC's independent reserves evaluator and auditor, and including certain corporate adjustments relating to estimated general and administrative costs and hedging, and excluding shareholder distributions and certain refinancing costs. Assumptions include average net production of approximately 62 Mboepd over the period of 2026 to 2030, average capital expenditures of approximately USD 5 per boe, average operating costs of approximately USD 18 to 20 per boe, average Brent oil prices of USD 65 to 95 per bbl escalating by 2% per year, and average Brent to Western Canadian Select differentials and average gas prices as estimated by IPC's independent reserves evaluator and auditor and as further described in the AIF. IPC's current business plans and assumptions, and the business environment, are subject to change. Actual results may differ materially from forward-looking estimates and forecasts.

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, 2025 (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.sedarplus.ca) or IPC's website (www.international-petroleum.com).

Management of IPC approved the production, operating costs, operating cash flow, capital and decommissioning expenditures and free cash flow guidance and estimates contained herein as of the date of this MD&A. The purpose of these guidance and estimates is to assist readers in understanding IPC's expected and targeted financial results, and this information may not be appropriate for other purposes.

RESERVES AND RESOURCES 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 and France/Malaysia are effective as of December 31, 2025, and are included in the reports prepared by Sproule International Limited and ERC Equipoise Ltd., respectively (collectively, Sproule ERCE), an independent qualified reserves evaluator and auditor, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Sproule ERCE's December 31, 2025 price forecasts.

The price forecasts used in the Sproule ERCE reports, are available on the website of Sproule ERCE (sproule-erce.com) and are contained in the AIF. These price forecasts are as at December 31, 2025 and may not be reflective of current and future forecast commodity prices.

The reserve life index (RLI) is calculated by dividing the 2P reserves of 521 MMboe as at December 31, 2025, by the mid-point of the 2026 CMD production guidance of 44,000 to 47,000 boepd.

The product types comprising the 2P reserves and contingent resources described in this MD&A are contained in the AIF. See also "Supplemental Information regarding Product Types" below. Light, medium and heavy crude oil and bitumen 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 percent 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 commercial contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable. Where risked resources are presented, they have been adjusted based on the chance of development by multiplying the unrisked values by the chance of development.

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 this 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 this MD&A. References to "contingent resources" do not constitute, and should be distinguished from, references to "reserves".

2P reserves and contingent resources included in the reports prepared by Sproule ERCE have been aggregated. 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 and contingent resources. 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 reserves and resources evaluations will be attained and variances could be material.

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.

Supplemental Information regarding Product Types
The following table is intended to provide supplemental information about the product type composition of IPC's net average daily production figures provided in this document:

	Heavy Crude Oil (Mbopd)	Light and Medium Crude Oil (Mbopd)	Conventional Natural Gas (per day)	Total (Mboepd)
Three months ended				
June 30, 2026	22.4	5.7	84.8 MMcf (14.1 Mboe)	42.2
June 30, 2025	22.7	5.9	89.8 MMcf (15.0 Mboe)	43.6
Six months ended				
June 30, 2026	22.4	6.0	85.2 MMcf (14.2 Mboe)	42.6
June 30, 2025	23.0	6.2	89.0 MMcf (14.8 Mboe)	44.0
Year ended December 31, 2025				
December 31, 2025	23.6	6.4	89.6MMcf (14.9 Mboe)	44.9

This MD&A also makes reference to IPC's forecast total average daily production of 44,000 to 47,000 boepd for 2026. IPC estimates that approximately 57% of that production will be comprised of heavy crude oil, approximately 12% will be comprised of light and medium crude oil and approximately 31% will be comprised of conventional natural gas.

OTHER SUPPLEMENTARY INFORMATION

Currency Abbreviations

CAD	Canadian dollar
MCAD	Million Canadian dollar
EUR	Euro
MEUR	Million Euro
USD	US dollar
MUSD	Million US dollar
MYR	Malaysian Ringgit
MMYR	Million Malaysian Ringgit

Oil related terms and measurements

AECO	The daily average benchmark price for natural gas at the AECO hub in southeast Alberta
AESO	Alberta Electric System Operator
API	An indication of the specific gravity of crude oil on the API (American Petroleum Institute) gravity scale
ARV	Argus WCS Houston (represents the differential, in USD, between a barrel of WCS quality in Houston and WTI)
ASP	Alkaline surfactant polymer (an EOR process)
bbl	Barrel (1 barrel = 159 litres)
boe	Barrels of oil equivalents
boepd	Barrels of oil equivalents per day
bopd	Barrels of oil per day
Bcf	Billion cubic feet
C5	Condensate
CO_2e	Carbon dioxide equivalents, including carbon dioxide, methane and nitrous oxide
Empress	The benchmark price for natural gas at the Empress point at the Alberta/Saskatchewan border
EOR	Enhanced Oil Recovery
FPSO	Floating Production Storage and Offloading (facility)
GJ	Gigajoules
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
Mcfpd	Thousand cubic feet per day
MMcf	Million cubic feet
MW	Mega watt
MWh	Mega watt per hour
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage
WTI	West Texas Intermediate
WCS	Western Canadian Select

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