Q3

International Petroleum Corporation

Management's Discussion and Analysis

For the three and nine months ended September 30, 2026

International Petroleum Corp.

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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 23.

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 November 3, 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 nine months ended September 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:

	September 30, 2026		September 30, 2025		December 31, 2025	
	Average	Period end	Average	Period end	Average	Year end
1 EUR equals USD	1.1616	1.1355	1.1180	1.1741	1.1293	1.1750
1 USD equals CAD	1.3851	1.4183	1.3993	1.3922	1.3975	1.3692
1 USD equals MYR	4.0108	4.0780	4.3265	4.2085	4.2791	4.0580

HIGHLIGHTS

Q3 2026 Business Highlights

- Average net production of approximately 44,000 barrels of oil equivalent per day (boepd) for the third quarter of 2026, in line with guidance for the period (56% heavy crude oil, 12% light and medium crude oil and 32% natural gas).[1]
- Production ramp-up at Blackrod Phase 1 progressed according to plan in the third quarter after successfully achieving first oil in May 2026, ahead of schedule and on budget.
- Sale of non-core asset in Canada completed in the third quarter for MCAD 70.
- 1.1 million IPC common shares purchased and cancelled during Q3 2026 under the normal course issuer bid (NCIB).
- IPC plans to seek Toronto Stock Exchange (TSX) approval for the renewal of the NCIB for the twelve month period commencing in early December 2026.

Q3 2026 Financial Highlights

- Operating costs per boe of USD 20.9 for Q3 2026, in line with guidance for the period.[3]
- Operating cash flow (OCF) generation of MUSD 79 for Q3 2026.[3]
- Capital and decommissioning expenditures of MUSD 37 for Q3 2026.
- Free cash flow (FCF) generation for Q3 2026 amounted to MUSD 27.[3]
- Net result of MUSD 60 for Q3 2026, including the gain on sale of assets in Canada during the quarter of MUSD 45.
- Net debt of MUSD 473 as at September 30, 2026, down from MUSD 509 as at June 30, 2026.[3]

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 275 and 350 (assuming Brent USD 80 to 110 per barrel for the remainder of 2026) from previous guidance of between MUSD 230 and 330 (assuming Brent USD 70 to 90 per barrel).[3][4]
- Full year 2026 capital and decommissioning expenditures guidance forecast revised to MUSD 185, following the addition of capital activity at the producing assets.
- Full year 2026 FCF revised guidance estimated at between MUSD 35 and 110 (assuming Brent USD 80 to 110 per barrel for the remainder of 2026) from previous guidance of between MUSD 10 and 110 (assuming Brent USD 70 to 90 per barrel).[3][4]

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2026	2025	2026	2025
Revenue	**211,955**	172,297	**570,703**	509,681
Gross profit	**52,333**	32,066	**127,602**	99,878
Net result	**59,901**	3,802	**82,580**	33,883
Operating cash flow[3]	**79,384**	66,102	**213,637**	195,765
Free cash flow[3]	**27,348**	(23,083)	**14,157**	(124,507)
EBITDA[3]	**79,382**	62,106	**207,527**	184,571
Net cash/(debt)[3]	**(472,809)**	(434,822)	**(472,809)**	(434,822)

OPERATIONS REVIEW

Business Overview

During the third quarter of 2026, benchmark international oil prices remained at elevated levels, with Brent oil prices averaging over USD 97 per barrel during the quarter. Market volatility continued during the quarter given the ongoing conflicts in the Middle East as well as uncertainties leading up to the fall midterm elections in the United States. The International Energy Agency (IEA) member countries' strategic reserves release (SPR) continued during the quarter to attempt to alleviate some of the worldwide energy supply disruptions. As part of the SPR releases, G7 and IEA members also agreed to prioritize diesel fuel releases in order to combat high diesel prices, particularly in the US and Europe, which should add to the demand for heavy oil. The crude oil market remains tight and supported by geopolitical concerns over energy security. IPC retains full exposure to West Texas Intermediate (WTI) and Brent oil price upside with no hedges in place for these benchmark prices.

The third quarter 2026 WTI to Western Canadian Select (WCS) price differential averaged approximately USD 14 per barrel, with the differential widening at the end of the third quarter and into the fourth quarter. The WTI to WCS differential remains sensitive to refinery demand for heavy crude on the US Gulf Coast and the availability of competing heavy crude supplies. IPC is well-positioned to partially mitigate the differential increase with 2026 full year WTI to WCS differential hedges for 5,000 bopd at USD -12.50 per barrel. In addition, IPC has hedged from July 2026 to December 2027, 5,000 bopd and from January 2027 to December 2027, a further 5,000 bopd 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 bopd 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 1.55 per Mcf for the third quarter of 2026, with gas demand during the summer months being typically lower than in colder months. The positive news for the Canadian gas market during the third quarter included closing of the acquisition by Shell of a large Canadian gas producer and the decision by the owners of LNG Canada to proceed with Phase 2 of that project. These strategic moves show international optimism on the strength and stability of the Canadian gas market which could benefit future Canadian gas prices. IPC implemented hedges for 15,000 GJ (approximately 14,500 Mcf) per day at CAD 2.73 per GJ (approximately CAD 2.84 per Mcf) from April to October 2026.

Third Quarter 2026 Highlights and Full Year 2026 Guidance

During the third quarter of 2026, IPC's portfolio delivered average net production of 44,000 boepd, in line with the guidance for the quarter. The producing assets in Canada, Malaysia and France benefited from increased activity and strong oil commodity prices. 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 third quarter and the first nine months of 2026 were, respectively, USD 20.9 and USD 19.2, 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 third quarter of 2026 was robust at USD 79 million. Full year 2026 OCF guidance is tightened to USD 275 to 350 million (assuming Brent USD 80 to 110 per barrel for the remainder of 2026).[(3)(4)]

Capital and decommissioning expenditure for the third quarter of 2026 was USD 37 million. Full year 2026 capital and decommissioning expenditure is revised to USD 185 million, largely attributed to the addition of capital activity at the Canadian producing assets to take advantage of elevated commodity prices.

Free cash flow (FCF) generation was USD 27 million during the third quarter of 2026, representing a seven times increase in FCF compared to the second quarter of 2026. As production continues to grow in Q4 2026 and into 2027, IPC is strongly positioned for increased FCF generation. Full year 2026 FCF guidance is modified to USD 35 to 110 million (assuming Brent USD 80 to 110 per barrel for the remainder of 2026).[(3)(4)]

As at September 30, 2026, IPC's net debt position was USD 473 million, from a net debt position of USD 509 million as at June 30, 2026. IPC's net debt to trailing twelve-month EBITDA to end Q3 2026 is 1.8 times, after being above 2 times for the prior reporting periods in 2026. Rapid deleveraging is expected to continue in this high commodity price environment.[(3)]

As previously announced, IPC has increased the facility size of its Canadian credit facility to approximately USD 250 million and extended the maturity of that facility to May 2028. IPC also previously announced the 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 in 2026, supports IPC in following through on its key strategic objectives to maximize stakeholder value.

Stakeholder Returns: Normal Course Issuer Bid

IPC renewed the current NCIB in December 2025, with the ability to repurchase up to approximately 6.5 million common shares up to early December 2026. Under the 2025/2026 NCIB, IPC repurchased and cancelled approximately 1.1 million common shares during the third quarter of 2026. The average price of common shares repurchased under the 2025/2026 NCIB during the third quarter was around SEK 234 / CAD 34 per share.

As at September 30, 2026, IPC had a total of 111,727,666 common shares issued and outstanding and IPC held no common shares in treasury. As at November 3, 2026, IPC had a total of 111,521,876 common shares issued and outstanding and IPC held no common shares in treasury.

The IPC Board of Directors has approved, subject to acceptance by the Toronto Stock Exchange (TSX), the renewal of IPC's NCIB for a further twelve months from December 2026 to early December 2027. We expect that the 2026/2027 NCIB will permit IPC to purchase through the TSX and Nasdaq Stockholm, and cancel, up to a further approximately 6.3 million IPC common shares, representing approximately 5.7% of the total current outstanding common shares (or 10% of IPC's "public float" under applicable TSX rules).

Blackrod

The Blackrod asset is 100% owned by IPC and hosts the largest booked reserves and contingent resources within the IPC portfolio. Blackrod Phase 1 targets 30,000 bopd production through the newly commissioned Central Processing Facility (CPF) and contains 311 MMboe of 2P reserves, with the full Blackrod field having an additional 1,145 MMboe of 2C resources.[(1)(2)]

As previously announced, first oil at Blackrod Phase 1 was successfully achieved at the end of May 2026, ahead of schedule and on budget (MUSD 855). During the third quarter, IPC successfully completed the first, and subsequently ongoing, oil sales from the Blackrod commercial plant in Edmonton, proving the effectiveness of the pipeline connected asset.

The production ramp up progressed as planned during the third quarter, with current spot rates exceeding 10,000 bopd and early results indicating encouraging subsurface performance. At the time of this report, around 16 well pairs are currently on production, a further 14 are planned for conversion before year-end, and 10 well pairs are expected to be converted to production in early 2027. An incremental 6 sustaining well pairs were successfully drilled to take advantage of economies of scale and for redundancy.

With excellent overall Phase 1 project delivery and initial performance, IPC has sanctioned incremental resource maturation works through seismic and stratigraphic well drilling outside of the initial development area planned to start in late Q4 2026. The low-cost resource conversion work is expected to allow for additional bookable reserves and positively position IPC for an eventual future phase expansion. In addition, IPC has sanctioned a butane blending project supported by robust economics through reduced condensate blending needs with completion expected by end 2027.

Blackrod is a multi-generational asset that has been 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)]

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 and in the MD&A.

(4) OCF and FCF forecasts at Brent USD 80 to 110 per barrel assume Brent to WTI differential of USD 5 to 10 per barrel and average WTI to WCS differential of USD 22 per barrel for the remainder of 2026. OCF and FCF forecasts assume gas price on average of approximately CAD 2.25 per Mcf for the remainder of 2026.

Operations Overview

Q3 2026 Overview

In Q3 2026, IPC continued to demonstrate its commitment to operational excellence, delivering production performance and operating expenditure in line with IPC's latest guidance.

At the end of Q1 2026, supported by an improved pricing environment and strong operational performance, IPC increased its 2026 capital expenditure budget to enable additional production well drilling in France and Canada. By the end of Q3 2026, four new Basal Quartz production wells had been successfully drilled in the Suffield Area in Canada. All four wells are online and cleaning up, with initial production in line with expectations. In France, the four planned sidetrack wells at Fontaine-au-Bron and Villeperdue were drilled and brought online, with initial production in line with forecast.

In response to continued strong commodity prices in Q3 2026, IPC accelerated the drilling of two additional infill production wells at Onion Lake Thermal in Canada. Both wells were drilled during the quarter and are expected to be brought online late in Q4 2026.

At Blackrod Phase 1, the production ramp-up continued during Q3 2026. By the end of the quarter, 12 well pairs had been converted and brought on to oil production, with further well pair conversions ongoing. Production increased through the quarter, and a further step-up is expected during Q4 2026 as additional well pairs are converted and brought online.

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 Q3 2026 was 44.0 Mboepd, in line with IPC's latest quarterly guidance. This performance was supported by strong production from the Canadian assets, the continued production ramp-up of Blackrod Phase 1, and better-than-forecast production in France.

IPC remains well positioned to deliver full-year average net production within the guidance range of 44,000 to 47,000 boepd, supported by strong operational performance during the first nine months of 2026 and the continued production ramp-up at Blackrod Phase 1.

The production during Q3 2026 and the first nine months of 2026 with comparatives is summarized below:

Production in Mboepd	Three months ended September 30		Nine months ended September 30		Year ended December 31
	2026	2025	**2026**	2025	2025
Crude oil					
Canada – Northern Assets	17.0	15.8	15.3	14.5	14.7
Canada – Southern Assets	8.4	9.9	8.8	10.4	10.2
Malaysia	2.4	3.2	2.9	2.8	3.0
France	2.3	2.1	2.0	2.1	2.1
Total crude oil production	**30.1**	31.0	**29.0**	29.8	30.0
Gas					
Canada – Northern Assets	0.4	0.5	0.4	0.4	0.4
Canada – Southern Assets	13.5	14.4	13.7	14.4	14.5
Total gas production	**13.9**	14.9	**14.1**	14.8	14.9
Total production	**44.0**	45.9	**43.1**	44.6	44.9
Quantity in MMboe	**4.04**	4.22	**11.75**	12.19	16.38

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

CANADA

Production in Mboepd	Working Interest (WI)	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2026	2025	2026	2025	2025
- Oil Onion Lake Thermal	100%	10.6	13.1	11.3	12.0	12.2
- Oil Suffield Area	100%	7.6	8.7	7.9	9.0	8.9
- Oil Blackrod	100%	5.1	–	2.3	–	–
- Oil Other	50-100%	2.1	3.9	2.6	3.9	3.8
- Gas	~100%	13.9	14.9	14.1	14.8	14.9
Canada		**39.3**	40.6	**38.2**	39.7	39.8

Production
Net production from IPC's assets in Canada during Q3 2026 was in line with guidance at 39.3 Mboepd with stable operational performance at the major oil and gas producing assets.

Organic Growth and Capital Projects
During Q3 2026, IPC increased capital activity in Canada to take advantage of the strong commodity price environment. IPC drilled two additional infill production wells at Onion Lake Thermal during the quarter. The wells are expected to be brought online in late Q4 2026.

In the Suffield Area, drilling of four Basal Quartz production wells was completed during Q3 2026. The wells are cleaning up, with initial production results in line with expectations.

At Blackrod Phase 1, construction and commissioning activities have been completed. During Q3 2026, the production and injection well pairs continued warming through steam circulation, and seven additional well pairs were converted to production, bringing the total to 12 wells on production by quarter-end. At the time of this report, there were 16 well pairs converted to production. Initial production is in line with expectations, and rates are expected to increase during the final quarter of 2026. Plateau production of 30,000 bopd is forecast to be achieved by the end of 2027.

MALAYSIA

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2026	2025	2026	2025	2025
Bertam	100%	**2.4**	3.2	**2.9**	2.8	3.0

Production
Net production in Malaysia during Q3 2026 was 2.4 Mboepd, below guidance, due to well A16 being shut in following an Electrical Submersible Pump (ESP) failure.

Operational Projects
Planning and scheduling of the Bertam A16 production well maintenance is being progressed.

FRANCE

Production in Mboepd	WI	Three months ended September 30		Nine months ended September 30		Year ended December 31
		2026	2025	2026	2025	2025
France	35–100%[1]	**2.3**	2.1	**2.0**	2.1	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 Q3 2026 was ahead of guidance at 2.3 Mboepd.

Organic Growth
In France, drilling of three sidetrack wells at Fontaine-au-Bron and one at Villeperdue commenced in Q2 2026, with all four wells completed by the end of Q3 2026. The four wells are online and undergoing clean up, with initial production results in line with expectations.

FINANCIAL REVIEW

Financial Results

Selected Interim Financial Information

Selected consolidated statement of operations is as follows:

USD Thousands	Q3-26	Q2-26	Q1-26	Q4-25	Q3-25	Q2-25	Q1-25	Q4-24
Revenue	**211,955**	185,738	173,010	176,207	172,297	158,892	178,492	199,124
Gross profit	**52,333**	38,094	37,175	28,242	32,066	23,663	44,149	42,774
Net result	**59,901**	9,917	12,762	(4,942)	3,802	13,850	16,231	415
Earnings per share – USD	**0.53**	0.09	0.11	(0.04)	0.03	0.12	0.14	0.00
Earnings per share fully diluted – USD	**0.52**	0.09	0.11	(0.04)	0.03	0.12	0.13	0.00
Operating cash flow[1]	**79,384**	66,518	67,735	63,138	66,102	54,873	74,790	78,158
Free cash flow[1]	**27,348**	3,895	(17,086)	(28,627)	(23,083)	(58,252)	(43,172)	(61,476)
EBITDA[1]	**79,382**	63,856	64,289	58,966	62,106	51,519	70,946	76,184
Net cash/(debt) at period end[1]	**(472,809)**	(508,999)	(513,413)	(483,615)	(434,822)	(374,977)	(314,255)	(208,528)

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

Summarized consolidated balance sheet information is as follows:

USD Thousands	September 30, 2026	December 31, 2025
Non-current assets	1,847,103	1,847,327
Current assets	210,965	130,302
Total assets	**2,058,068**	1,977,629
Total non-current liabilities	917,020	890,204
Current liabilities	194,413	160,248
Total liabilities	**1,111,433**	1,050,452
Net assets	**946,635**	927,177
Working capital (including cash)	**16,552**	(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 – September 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	129,479	58,921	23,051	19,560	–	**231,011**
Gas and NGLs	63	7,929	–	–	–	**7,992**
Net sales of oil and gas	**129,542**	**66,850**	**23,051**	**19,560**	–	**239,003**
Change in under/over lift position	–	–	–	37	–	**37**
Royalties	(18,350)	(10,765)	–	(1,173)	–	**(30,288)**
Hedging settlement	256	2,628	–	–	–	**2,884**
Other operating revenue	–	–	–	170	149	**319**
Revenue	**111,448**	**58,713**	**23,051**	**18,594**	**149**	**211,955**
Operating costs	(33,043)	(29,138)	(12,875)	(9,529)	–	**(84,585)**
Cost of blending	(38,749)	(5,187)	–	–	–	**(43,936)**
Change in inventory position	(1,495)	216	545	495	–	**(239)**
Depletion	(11,367)	(11,149)	(4,440)	(3,472)	–	**(30,428)**
Exploration and business development costs	–	–	–	–	(434)	**(434)**
Gross profit/(loss)	**26,794**	**13,455**	**6,281**	**6,088**	**(285)**	**52,333**

	Three months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	99,686	54,768	15,581	11,870	–	181,905
Gas and NGLs	25	4,782	–	–	–	4,807
Net sales of oil and gas	99,711	59,550	15,581	11,870	–	186,712
Change in under/over lift position	–	–	–	1,585	–	1,585
Royalties	(14,269)	(7,672)	–	(931)	–	(22,872)
Hedging settlement	1,886	4,701	–	–	–	6,587
Other operating revenue	–	–	–	197	88	285
Revenue	87,328	56,579	15,581	12,721	88	172,297
Operating costs	(22,707)	(33,758)	(10,908)	(8,254)	–	(75,627)
Cost of blending	(27,588)	(4,863)	–	–	–	(32,451)
Change in inventory position	(26)	(353)	2,327	(253)	–	1,695
Depletion	(10,360)	(12,425)	(6,504)	(2,956)	–	(32,245)
Depreciation of other assets	–	–	(1,419)	–	–	(1,419)
Exploration and business development costs	–	–	–	–	(184)	(184)
Gross profit/(loss)	26,647	5,180	(923)	1,258	(96)	32,066

	Nine months ended – September 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	355,505	180,513	70,132	57,232	–	**663,382**
Gas and NGLs	228	29,233	–	–	–	**29,461**
Net sales of oil and gas	**355,733**	**209,746**	**70,132**	**57,232**	–	**692,843**
Change in under/over lift position	–	–	-	(4,707)	–	**(4,707)**
Royalties	(50,359)	(28,059)	-	(2,906)	–	**(81,324)**
Hedging settlement	(24,936)	(12,037)	–	–	–	**(36,973)**
Other operating revenue	–	–	–	536	328	**864**
Revenue	**280,438**	**169,650**	**70,132**	**50,155**	**328**	**570,703**
Operating costs	(74,144)	(86,984)	(37,316)	(27,818)	–	**(226,262)**
Cost of blending	(113,354)	(17,037)	–	–	–	**(130,391)**
Change in inventory position	(632)	230	4,569	554	–	**4,721**
Depletion	(29,252)	(34,542)	(16,007)	(9,360)	–	**(89,161)**
Exploration and business development costs	–	–	–	–	(2,008)	**(2,008)**
Gross profit/(loss)	**63,056**	**31,317**	**21,378**	**13,531**	**(1,680)**	**127,602**

	Nine months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other	Total
Crude oil	283,855	172,623	42,785	36,147	–	535,410
Gas and NGLs	204	26,335	–	–	–	26,539
Net sales of oil and gas	284,059	198,958	42,785	36,147	–	561,949
Change in under/over lift position	–	–	–	4,285	–	4,285
Royalties	(39,321)	(26,293)	–	(2,503)	–	(68,117)
Hedging settlement	3,279	7,467	–	–	–	10,746
Other operating revenue	–	–	–	572	246	818
Revenue	248,017	180,132	42,785	38,501	246	509,681
Operating costs	(61,673)	(97,583)	(31,257)	(24,789)	–	(215,302)
Cost of blending	(87,265)	(16,181)	–	–	–	(103,446)
Change in inventory position	143	(509)	5,869	(427)	–	5,076
Depletion	(28,042)	(37,379)	(17,146)	(8,015)	–	(90,582)
Depreciation of other assets	–	–	(4,797)	–	–	(4,797)
Exploration and business development costs	–	–	–	–	(752)	(752)
Gross profit/(loss)	71,180	28,480	(4,546)	5,270	(506)	99,878

Three and nine months ended September 30, 2026 Review

Revenue

Total revenue amounted to USD 211,955 thousand for Q3 2026, compared to USD 172,297 thousand for Q3 2025 and USD 570,703 thousand for the first nine months of 2026 compared to USD 509,681 thousand for the first nine months of 2025 is analyzed as follows:

	Three months ended September 30		Nine months ended September 30	
USD Thousands	**2026**	2025	**2026**	2025
Crude oil sales	231,011	181,905	663,382	535,410
Gas and NGL sales	7,992	4,807	29,461	26,539
Change in under/overlift position	37	1,585	(4,707)	4,285
Royalties	(30,288)	(22,872)	(81,324)	(68,117)
Hedging settlement	2,884	6,587	(36,973)	10,746
Other operating revenue	319	285	864	818
Revenue	**211,955**	172,297	**570,703**	509,681

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

Crude oil sales

	Three months ended – September 30, 2026				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	129,479	58,921	23,051	19,560	**231,011**
- Quantity sold in bbls	1,842,758	825,435	181,683	201,552	**3,051,428**
- Average price realized USD per bbl	70.26	71.38	126.87	97.05	**75.71**

	Three months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	99,686	54,768	15,581	11,870	181,905
- Quantity sold in bbls	1,849,991	993,748	209,107	170,751	3,223,597
- Average price realized USD per bbl	53.88	55.11	74.51	69.52	56.43

Crude oil revenue was 27% higher in Q3 2026 compared to Q3 2025 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 Q3 2026, WTI averaged USD 86 per bbl compared to USD 65 per bbl for Q3 2025 and the average discount to WCS used in IPC's pricing formula was USD 14 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 Q3 2026 and one cargo lifting in Q3 2025. Produced unsold oil barrels from Bertam at the end of Q3 2026 amounted to 139,000 bbls, see Change in Inventory Position section below. The average Dated Brent crude oil price was USD 97 per bbl for Q3 2026 compared to USD 69 per bbl for the comparative period.

	Nine months ended – September 30, 2026				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	355,505	180,513	70,132	57,232	**663,382**
- Quantity sold in bbls	5,220,034	2,601,777	621,901	649,218	**9,092,930**
- Average price realized USD per bbl	68.10	69.38	112.77	88.16	**72.96**

	Nine months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Crude oil sales					
- Revenue in USD thousands	283,855	172,623	42,785	36,147	535,410
- Quantity sold in bbls	5,153,175	3,086,686	580,067	507,167	9,327,095
- Average price realized USD per bbl	55.08	55.93	73.76	71.27	57.40

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 24% during the first nine months of 2026 compared to the first nine 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 nine months of 2026, WTI averaged USD 83 per bbl compared to USD 67 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 94 per bbl for the first nine months of 2026 compared to USD 71 per bbl for the comparative period.

Gas and NGL sales

	Three months ended – September 30, 2026		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	63	7,929	**7,992**
- Quantity sold in Mcf	64,840	6,905,840	**6,970,680**
- Average price realized USD per Mcf	0.97	1.15	**1.15**

	Three months ended – September 30, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	25	4,782	4,807
- Quantity sold in Mcf	69,170	7,404,566	7,473,736
- Average price realized USD per Mcf	0.37	0.65	0.64

Gas and NGL sales revenue was 66% higher for the Q3 2026 compared to Q3 2025, mainly due to higher gas prices achieved.

IPC's achieved gas price is based on AECO pricing plus a premium. For Q3 2026, IPC realized an average price of CAD 1.58 per Mcf compared to AECO average pricing of CAD 1.55 per Mcf.

	Nine months ended – September 30, 2026		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	228	29,233	**29,461**
- Quantity sold in Mcf	205,299	20,430,026	**20,635,325**
- Average price realized USD per Mcf	1.11	1.43	**1.43**

	Nine months ended – September 30, 2025		
	Canada – Northern Assets	Canada – Southern Assets	Total
Gas and NGL sales			
- Revenue in USD thousands	204	26,335	26,539
- Quantity sold in Mcf	212,242	21,611,998	21,824,240
- Average price realized USD per Mcf	0.96	1.22	1.22

Gas and NGL sales revenue was 11% higher for the first nine months of 2026 compared to the first nine months of 2025, mainly due to higher gas prices achieved.

IPC's achieved gas price is based on AECO pricing plus a premium. For the first nine months of 2026, IPC realized an average price of CAD 1.94 per Mcf compared to AECO average pricing of CAD 1.71 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 Q3 2026 amounted to a gain of USD 2,884 thousand, and a loss for the first nine months of 2026 of USD 36,973 thousand which consisted of a loss of USD 39,388 thousand on the oil contracts and a gain of USD 2,415 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 128,760 thousand for Q3 2026 compared to USD 106,383 thousand for Q3 2025 and USD 351,932 thousand for the first nine months of 2026 compared to the USD 313,672 thousand for the first nine months of 2025, and is analyzed as follows:

	Three months ended – September 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	33,043	29,138	12,875	9,529	–	**84,585**
USD/boe[2]	20.59	14.48	58.98	45.59	n/a	**20.91**
Cost of blending	38,749	5,187	–	–	–	**43,936**
Change in inventory position	1,495	(216)	(545)	(495)	–	**239**
Production costs	**73,287**	**34,109**	**12,330**	**9,034**	–	**128,760**

	Three months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	22,707	33,758	10,908	8,254	–	75,627
USD/boe[2]	15.16	15.10	37.44	41.54	n/a	17.91
Cost of blending	27,588	4,863	–	–	–	32,451
Change in inventory position	26	353	(2,327)	253	–	(1,695)
Production costs	50,321	38,974	8,581	8,507	–	106,383

	Nine months ended – September 30, 2026					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	74,144	86,984	37,316	27,818	–	**226,262**
USD/boe[2]	17.31	14.12	47.42	50.51	n/a	**19.25**
Cost of blending	113,354	17,037	–	–	–	**130,391**
Change in inventory position	632	(230)	(4,569)	(554)	–	**(4,721)**
Production costs	**188,130**	**103,791**	**32,747**	**27,264**	–	**351,932**

	Nine months ended – September 30, 2025					
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Other[3]	Total
Operating costs[1]	61,673	97,583	34,785	24,789	(3,528)	215,302
USD/boe[2]	15.15	14.12	45.28	42.33	n/a	17.66
Cost of blending	87,265	16,181	–	–	–	103,446
Change in inventory position	(143)	509	(5,869)	427	–	(5,076)
Production costs	148,795	114,273	28,916	25,216	(3,528)	313,672

[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 current period and for 2025.
[3] Included in the Malaysia operating costs to Q3 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 40.69 for the nine months ended September 30, 2025.

Operating costs
Operating costs amounted to USD 84,585 thousand for Q3 2026 compared to USD 75,627 thousand for Q3 2025 and amounted to USD 226,262 thousand for the first nine months of 2026 compared to USD 215,302 thousand for the comparative period. Operating costs per boe amounted to USD 20.91 per boe in Q3 2026 in line with the guidance for the quarter compared with USD 17.91 per boe in Q3 2025. At Blackrod Phase 1, the production ramp-up continued during Q3 2026. Plateau production of 30,000 bopd is forecast to be achieved by the end of 2027. During ramp-up of SAGD projects, operating and transportation costs are largely fixed in nature regardless of production volumes. IPC anticipates that operating cost per barrel from Blackrod Phase 1 will materially decrease as production increases.

Operating costs per boe in Malaysia increased in Q3 2026 compared to Q3 2025 due to well maintenance in Q3 2026 and 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 43,936 thousand for Q3 2026 compared to USD 32,451 thousand for Q3 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 Q3 2026, IPC had crude entitlement of 139,000 bbls of oil on the FPSO Bertam facility being crude produced but not yet sold.

Depletion costs
The total depletion and decommissioning costs amounted to USD 30,428 thousand for Q3 2026 compared to USD 32,245 thousand for Q3 2025.

The depletion charge is analyzed in the following tables:

	Three months ended – September 30, 2026				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	11,367	11,149	4,440	3,472	**30,428**
USD per boe	7.08	5.54	20.34	16.61	**7.52**

	Three months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	10,360	12,425	6,504	2,956	32,245
USD per boe	6.92	5.56	22.32	14.89	7.64

	Nine months ended – September 30, 2026				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	29,252	34,542	16,007	9,360	**89,161**
USD per boe[1]	6.83	5.63	20.34	17.00	**7.59**

	Nine months ended – September 30, 2025				
USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Depletion cost in USD thousands	28,042	37,379	17,146	8,015	90,582
USD per boe[1]	6.89	5.52	22.32	13.69	7.43

[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 Q3 2026 compared to USD 1,419 thousand for Q3 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 2,008 thousand for the first nine months of 2026 and USD 752 thousand for the first nine months of 2025.

Net financial items
Net financial items amounted to a charge of USD 12,541 thousand for Q3 2026, compared to a charge of USD 21,030 thousand for Q3 2025, and a charge of USD 55,663 thousand for the first nine months of 2026 compared to a charge of USD 39,726 thousand for the first nine months of 2025, and included no realized currency hedge loss and a net foreign exchange loss of USD 11,579 thousand for the first nine months of 2026 and compared to a realized currency hedge loss and a net foreign exchange gain of respectively USD 8,039 thousand and USD 8,502 thousand for the first nine 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 14,714 thousand for Q3 2026, compared to a charge of USD 14,778 thousand for Q3 2025 and a charge of USD 44,084 thousand for the first nine months of 2026 compared to a charge of USD 40,189 thousand for the first nine months of 2025.

The interest expense amounted to USD 9,924 thousand for Q3 2026, compared to USD 10,082 thousand for the comparative period in 2025 and USD 29,535 thousand for the first nine months of 2026 compared to USD 27,823 thousand for the first nine 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 4,079 thousand for Q3 2026 compared to USD 4,229 thousand for Q3 2025 and USD 12,364 thousand for the first nine months of 2026 compared to USD 12,301 thousand for the first nine months of 2025.

Income tax
The corporate income tax amounted to a charge of USD 20,886 thousand for Q3 2026 compared to a charge of USD 3,030 thousand for Q3 2025 and a charge of USD 28,417 thousand for the first nine months of 2026 compared to a charge of USD 13,876 thousand for the comparative period.

The current income tax amounted to a charge of USD 4,019 thousand for Q3 2026 and a charge of USD 5,687 thousand for the first nine months of 2026 and mainly related to Malaysia and 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 nine months of 2026 were as follows:

USD Thousands	Canada – Northern Assets	Canada – Southern Assets	Malaysia	France	Total
Development	113,017	15,804	1,993	21,956	**152,770**
Exploration and evaluation	1,915	–	–	–	**1,915**
	114,932	15,804	1,993	21,956	**154,685**

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 11,392 thousand as at September 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 September 30, 2026, are classified as non-current as there are no mandatory repayments within the next twelve months.

In addition, as at September 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 September 30, 2026, CAD 64 million (approximately USD 45 million) was drawn under the Canadian RCF. As at September 30, 2026, the Group also had a letter of credit facility in Canada (the "LC Facility"). As at September 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 September 30, 2026.

Net debt as at September 30, 2026 amounted to USD 473 million. Cash and cash equivalents held amounted to USD 22 million as at September 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 September 30, 2026, the Group had a working capital balance including cash of USD 16,552 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 and decommissioning costs, 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 September 30		Nine months ended September 30	
USD Thousands	**2026**	2025	**2026**	2025
Revenue	211,955	172,297	570,703	509,681
Production costs and net sales of diluent to third party[1]	(128,552)	(106,292)	(351,379)	(313,162)
Current tax	(4,019)	97	(5,687)	(754)
Operating cash flow	**79,384**	66,102	**213,637**	195,765

[1] Includes net sales of diluent to third parties amounting to USD 208 thousand for the three months ended September 30, 2026 and USD 553 thousand for the first nine 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 September 30		Nine months ended September 30	
USD Thousands	2026	2025	2026	2025
Operating cash flow - see above	79,384	66,102	213,637	195,765
Capital expenditures	(36,026)	(80,128)	(154,685)	(276,939)
Abandonment and farm-in expenditures[1]	(1,930)	5,374	(2,978)	2,956
General and administrative expenses before depreciation[2]	(4,021)	(3,899)	(11,797)	(11,948)
Cash financial items[3]	(10,059)	(10,532)	(30,020)	(34,341)
Free cash flow	**27,348**	(23,083)	**14,157**	(124,507)

[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 September 30		Nine months ended September 30	
USD Thousands	2026	2025	2026	2025
Net result	59,901	3,802	82,580	33,883
Net financial items	12,541	21,030	55,663	39,726
Income tax	20,886	3,030	28,417	13,876
Depletion and decommissioning costs	30,428	32,245	89,161	90,582
Depreciation of other tangible fixed assets	–	1,419	–	4,797
Exploration and business development costs	434	184	2,008	752
Sale of assets	(45,230)	–	(51,451)	(104)
Depreciation included in general and administrative expenses[1]	422	396	1,149	1,059
EBITDA	**79,382**	62,106	**207,527**	184,571

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

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

	Three months ended September 30		Nine months ended September 30	
USD Thousands	2026	2025	2026	2025
Production costs	128,760	106,383	351,932	313,672
Cost of blending	(43,936)	(32,451)	(130,391)	(103,446)
Change in inventory position	(239)	1,695	4,721	5,076
Operating costs	**84,585**	75,627	**226,262**	215,302

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

USD Thousands	September 30, 2026	December 31, 2025
Bank loans	(45,124)	(40,652)
Bonds	(450,000)	(450,000)
Cash and cash equivalents	22,315	7,037
Net cash/(debt)	**(472,809)**	(483,615)

Off-Balance Sheet Arrangements

IPC, through its subsidiary IPC Canada Ltd, had issued five letters of credit as at September 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.

During the first nine months of 2026, IPC purchased and cancelled a total of 1,099,086 shares under the NCIB. The average price of common shares purchased during the first nine months of 2026 was SEK 234 / CAD 34.

As at September 30, 2026, IPC had a total of 111,727,666 common shares issued and outstanding, with no common shares held in treasury.

As at November 3, 2026, IPC had a total of 111,521,876 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 38.1% of the outstanding common shares as at September 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 2,569,447 IPC Share Unit Plan awards outstanding as at November 3, 2026 of which 791,096 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 September 30, 2026:

MCAD	2026	2027	2028	2029	2030	Thereafter
Transportation service[1]	15.6	85.6	99.5	100.8	101.7	1,355.0
Power[2]	3.1	12.4	9.8	–	–	–
Total commitments	**18.7**	**98.0**	**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 15MW at a weighted average price of CAD 74.92/MWh from October 1, 2026 to December 31, 2028, and an additional 5MW at a weighted average price of CAD 58.31/MWh from October 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 nine 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 September 30, 2026, the Group had entered into oil, gas, currency 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 September 30, 2026, which are summarized as follows:

Period	Volume (barrels per day)	Type	Average Pricing
October 1, 2026 - December 31, 2026	5,000	WTI/WCS Differential	USD -12.50/bbl
October 1, 2026 - December 31, 2027	5,000	WCS (Hardisty to Houston)[1]	USD -7.55/bbl
January 1, 2027 - December 31, 2027	5,000	WCS (Hardisty to Houston)[1]	USD -7.50/bbl
October 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 September 30, 2026, which are summarized as follows:

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

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

Period	Volume (MWh)	Type	Average Pricing
October 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 8,053 thousand as at September 30, 2026.

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.

The Group entered into currency hedges to:
(i) sell a total USD 120 million for the period January 2027 to December 2027 at an average rate of CAD 1.3842 (buy CAD);
(ii) purchase a total EUR 15.6 million for the period January 2027 to October 2027 at an average rate of EUR 1.1432 (sell USD);
(iii) purchase a total MYR 72 million for the period January 2027 to October 2027 at an average rate of MYR 4.0331 (sell USD).

The above hedges are treated as effective and changes to the fair value are reflected in other comprehensive income. The hedges had a negative fair value of USD 1,290 thousand as at September 30, 2026.

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 nine months ended September 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 September 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 and Ferguson 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 ability of IPC to renew the NCIB and the number of common shares which may be purchased under a renewed NCIB;
- 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				
September 30, 2026	24.7	5.5	83.1 MMcf (13.8 Mboe)	44.0
September 30, 2025	24.5	6.5	89.3 MMcf (14.9 Mboe)	45.9
Nine months ended				
September 30, 2026	23.2	5.8	84.6 MMcf (14.1 Mboe)	43.1
September 30, 2025	23.5	6.3	89.1 MMcf (14.8 Mboe)	44.6
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	Megawatt
MWh	Megawatt-hour
NGL	Natural gas liquid
SAGD	Steam assisted gravity drainage
WTI	West Texas Intermediate
WCS	Western Canadian Select

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